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

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RTO Resilience Filings Seek Time, More Gas Coordination

By RTO Insider Staff

RTO officials asked FERC on Friday to allow their stakeholder processes time to develop additional resilience measures while urging the commission to require more coordination with natural gas operators and provide more information on cyber threats.

Friday was the deadline for the six jurisdictional RTOs and ISOs to respond to two dozen questions FERC presented in its January order rejecting the Department of Energy's call for price supports for coal and nuclear generators and creating the resilience docket (AD18-7). ERCOT also responded, although FERC's jurisdiction over the Texas grid is limited to NERC reliability rules. (See *DOE NOPR Rejected, 'Resilience' Debate Turns to RTOs, States*.)

The order asked RTOs to identify their resilience risks; whether they should assess their resource portfolios against contingencies from the loss of key infrastructure; and the bulk power system attributes that contribute to resilience.

ISO-NE expressed the most acute concerns among the RTOs, saying inadequate natural gas supplies could lead to load shedding on peak days by winter 2024. It said it will need until mid-2019 to develop solutions with its stakeholders.

PJM, however, said RTOs and jurisdictional transmission operators in non-RTO regions should be required to file rule changes needed to address resilience within nine to 12 months. "A deadline … would help ensure focus on these issues in the stakeholder process," PJM said.

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McIntyre Discloses Brain Tumor Surgery (p.41)

'Hesitancy' Around Western RTO, EIM Chair Says

By Jason Fordney

LOS ANGELES — Despite recent developments favoring more organized energy markets, Westerners still hold some "anxiety" and "hesitancy" about a new RTO in the region, says Doug Howe, chairman of the Western Energy Imbalance Market's (EIM) Governing Body.

Howe, a doctor of mathematics, independent consultant, former utility executive and former New Mexico regulator, joined the body when it was established in 2016.

At an EIM meeting in Los Angeles last week, *RTO Insider* asked Howe how he sees the Western landscape taking shape, and what his concerns are about a possible new Western RTO.

"My sense is still that there is a lot of hesitancy towards a full

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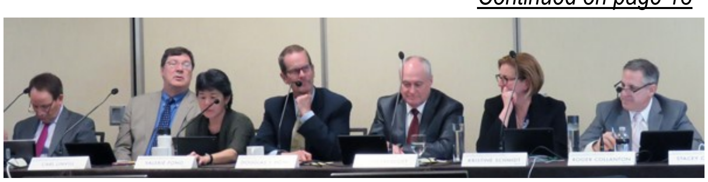

CAISO and EIM Governing Body personnel left to right: Keith Casey (CAISO), Carl Linvill, Valerie Fong, Doug Howe, John Prescott, Kristine Schmidt and Roger Collanton (CAISO). | © *RTO Insider*

Split FERC Approves ISO-NE CASPR Plan

By Rich Heidorn Jr.

FERC approved ISO-NE's two-stage capacity auction to accommodate state renewable energy procurements, with Commissioner Robert Powelson dissenting and Commissioners Cheryl LaFleur and Richard Glick leveling new criticism on the minimum offer price rule (MOPR) (ER18-619).

ISO-NE proposed the Competitive Auctions with Sponsored Policy Resources (CASPR) construct in January to address state regulators' concerns about ratepayer costs for policy-driven resources and generators' fears that out-of-market procurements would suppress capacity prices.

Under CASPR, ISO-NE will clear the Forward Capacity Auction as it does today, applying the MOPR to new capacity offers to prevent price suppression. In the second Substitution Auction (SA), generators with retirement bids that cleared in the primary auction would transfer their obligations to subsidized new resources that did not clear

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IN THIS WEEK'S ISSUE

Stakeholder Soapbox

Competition Gives Everyone Better, Cheaper Energy Choices

By Anne Hoskins and Dan Dolan

Hoskins

Open markets drive competition. Competition drives innovation and affordability. Case in point: Today, more and more consumers are utilizing innovative battery solutions — with many powered by rooftop solar — to provide clean energy to homes and businesses. In the coming weeks, regulators will consider proposals by utilities in Massachusetts and New Hampshire that seek to fully control customer-owned batteries, or seek to reach into peoples' homes and actually own batteries. There is no reason for regulators to allow utility control or ownership of generation and storage resources that can be supplied competitively. With no natural monopoly to regulate or market failure to fix, enabling utility ownership and control will serve only to stifle innovation and impede competitive solutions. We urge regulators to consider a better future.

Dolan

The way Americans make and use electricity is in the midst of a remarkable evolution. For more than a century, we were unable to store electricity at our homes or businesses the way we store gasoline or recharge devices like our cell phones. Energy needed to be generated and consumed simultaneously. As a result of steep cost reductions in technology and competitive innovation, we are entering an exciting new era of empowerment. Consumers and businesses across the country are pairing batteries with rooftop solar. Large power plants are also now pairing with batteries to smooth spikes in demand. These new resources can enter markets, lowering costs for all consumers.

Twenty years ago, many states unleashed innovation by restructuring and creating competitive markets, no longer allowing monopoly utilities to own generation. That policy choice helped pave the way for consumers to benefit from electricity supply options and unleashed fierce competition in how electricity is produced.

The result? More efficiency. Thanks to increased competition in the marketplace, today it takes three plants to generate the same amount of electricity as it used to take four to generate. This in turn helped lower the price to produce power dramatically, though consumers' bills are still increasing, as utilities continue distribution and transmission spending and charge us more to transmit power. These efficiency gains and competitive investments have also helped power plants in New England drive down carbon dioxide emissions by more than 40% since 1990, now representing only half of the emissions of the transportation sector. The framework of a competitive and dynamic marketplace set the stage for more competitive storage options.

But the glide path for consumers and competitive markets is riddled with bumps along the way. Some utilities are seeking to own batteries in peoples' homes and businesses. Others are requesting the right to the energy in a consumer's battery, at the very least.

Their goal? To receive returns for their investors by controlling storage that was funded by consumer and business investments. In other words, utilities want to take control of a family's home battery, which was charged by the family's home solar system, and bid that electricity into the competitive wholesale markets themselves. That is anticompetitive and counter to public policy goals that encourage investments in a cleaner and more resilient electricity grid.

The New England Power Generators Association and residential solar and storage companies agree that utilities should not impede consumer energy and storage investments when there are competitive options available. Such utility ownership or control is a dramatic step away from open energy markets. Rate-based utility ownership of batteries stifles competition — both at the rooftop and large generator scale — and threatens to raise rates for everyone.

Let's get this right. Dozens of innovative companies are already stepping up to replace portions of our aging energy infrastructure with innovative storage solutions — competitively and with increased flexibility for consumers and generators. At the same time, however, utilities are spending tens of billions of dollars annually on building poles and wires. Some of these investments are necessary to replace power lines and substations at the end of their useful life, but some can be avoided with distributed energy solutions and large-scale storage. Consumers will foot the bill for utility infrastructure now and for decades into the future — if we don't allow competitive solutions to emerge. With the right policies in place, investments in competitive electricity supply and storage can improve resilience and affordability. By providing clear price signals, utilities or system operators can incentivize private storage assets, at all scales, to meet system demands. There is no need for utilities to own or control the assets.

As the National Energy Marketers Association, which represents global suppliers and major consumers of natural gas and electricity, wrote, "After nearly two decades of experience with competitive retail markets, it is abundantly clear that the anticompetitive impacts of monopoly utility participation in competitive energy markets … is poor public policy, is not in the public interest and deters and discourages the private capital investment and technology innovation."[1]

Dan Dolan, President, New England Power Generators Association. NEPGA's mission is to support competitive wholesale electricity markets in New England. We believe that open markets guided by stable public policies are the best means to provide reliable and competitively priced electricity for consumers.

Anne Hoskins, Chief Policy Officer at Sunrun. Sunrun is the nation's largest dedicated residential solar, storage and energy services company with a mission to create a planet run by the sun.

[1] "Comments of the National Energy Marketers Association." State of New York Public Service Commission. Case 14-M-0101. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. 9/22/14. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={929C1EFF-B6C6- 4779-934A-23EDD5DA11D2.

Institute for Electric Innovation Spring Forum

Visibility Key as EVs Seek Growth Beyond Early Adopters

By Rich Heidorn Jr.

WASHINGTON — Growing the electric vehicle market beyond early adopters will require creative regulations, an expanded charging network and a vastly improved customer experience, speakers told the Institute for Electric Innovation's (IEI) spring 2018 forum Wednesday.

"The early adopters were able to deal with some of the challenges of interacting with five different charging networks and the fact that sometimes stations didn't work; maybe they're in the back of a parking lot that wasn't well lit and it was kind of dangerous," said **Scott Fisher**, vice president of market development for Greenlots, which sells EV charging software and services.

Fisher said he senses increased momentum for EVs, with moves in Europe to ban diesel vehicles and Volvo announcing all its models will be electric-powered by 2019.

"There seems to be a commitment among large credible companies to create this positive customer experience. So, it's not going to cater to the 1% anymore. … To get to that 5% or 10% — that next stage of early adopters — thinking about the customer experience that's needed" is crucial, he said. "Some of it's in place, but making it more consistent is a really important objective."

Alan M. Oshima, CEO of Hawaiian Electric and the owner of a plug-in Ford Fusion, agreed. "The [conflicting] charging protocols we have right now is even worse than Betamax vs. VHS," said Oshima, who moderated the panel discussion.

"It can't be depending on niches. It can't just work in California or Massachusetts or New York," said **Mark S. Lantrip**, CEO of Southern Company Services. "Somehow we've got to think about how we bring everyone along. Until that, it's going to be a series of fits and starts."

Exhibit A is Georgia, which — thanks to a $5,000 state tax credit — was the fastest-growing EV market in the U.S. between 2010 and 2014, according to the Edison Electric Institute, which funds the Edison Foundation and IEI. When the tax credit expired, EV sales in the state plummeted. (The federal government continues to offer a $7,500 tax credit.) Still, with 25,500 EVs as of 2016, the state ranked second to California in EV sales between 2011 and 2016.

Wooing Newcomers

Although U.S. EV sales increased by 26% last year to almost 200,000, they still represented only 1% of new vehicle sales. Globally, EV sales jumped by more than 60% last year, with China responsible for more than half the sales in the third quarter.

Fisher said the best marketing EVs could get is more charging stations. "Whenever I talk to my liberal friends in Princeton, N.J., where I live, [they say] 'Oh, that's a great car, but where would I charge it?' If I have to explain to them, I've already kind of lost them."

Lisa Wood, IEI's executive director, said EVs also will benefit from the increasing visibility of electric fleets such as city buses, United Parcel Service delivery vans and school buses that can provide energy storage in summer. Electric companies have increased their EV fleets by more than 40% since 2015, according to EEI, with more than 70 companies investing more than $120 million last year alone.

Lantrip said proponents are discouraging potential adoptees from making the switch with talk of EVs' potential as distributed energy storage.

"We're trying to get people to just even entertain the idea of buying [an electric] car, and what I see in so many presentations on electric vehicles is they immediately go to vehicle-to-grid, vehicle-to-home, and that freaks out the average new potential buyer … because they just don't get it or want it. It's like, 'You're going to drain my battery?' We have to separate those two conversations."

Lantrip predicts EV penetration will not surge until there is price parity between EVs and conventional vehicles and charging times are reduced to five minutes. "We have to manage our expectations," he said, warning that current investments in the technology and charging infrastructure should be limited to "no regrets" steps while the market remains small and different technologies are competing for dominance.

About 80% of EV charging is done at home, where residents can use either a Level 1 charger (a standard AC outlet providing up to 1.5 kW of electricity that takes 30 hours to fully charge a 115-mile battery) or a Level 2 (a 240-V AC outlet delivering up to 9 kW, which can charge in 5.5 hours). Commercial charging locations with DC-powered fast chargers deliver 50 kW and reduce a 90-mile charge to 30 minutes. In Europe, a new generation of chargers is being installed offering 350 kW, which would complete a charge in 10 to 15 minutes, but no vehicles currently offered can use them.

Policy Questions for Regulators

Norm Saari, a member of the Michigan Public Service Commission, shared Lantrip's concern about investing in technology that could be rendered obsolete.

Saari said policymakers could be hesitant to act because of uncertainty over what is the "proven, right technology."

"[Do] you want to have a Level 1 or Level 2 or DC fast charging? Or do you want inductive charging on the road? Or let's forget about that. Let's go to hydrogen fuel cells instead. There's a lot of issues that still have to be resolved," Saari said.

The Michigan commission held its second

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Institute for Electric Innovation Spring Forum

Overheard

WASHINGTON — The Institute for Electric Innovation's spring 2018 forum Wednesday featured a discussion on corporate renewable energy procurement and an appearance by Rep. Yvette Clarke (D-N.Y.), co-chair of the newly formed Smart Cities Caucus. Here's some of what we heard.

Lisa Wood (left) and Rep. Yvette Clarke (D-N.Y.) | © RTO Insider

Electric Industry an 'Afterthought' to FCC?

Edison Electric Institute Executive Vice President and former FERC Commissioner Phil Moeller told Clarke that the electric industry feels like an afterthought in the Federal Communications Commission's discussions on the rollout of 5G cellular technology.

"We have another issue [at the FCC] with pole attachments and spectrum allocation, but particularly with [the] 5G network, our infrastructure is going to play a big role," Moeller said. "Safety has to come first. We could probably use your help at the Smart Cities Caucus to remind the FCC that our industry should not be an afterthought but should be at the table during some of these discussions."

"I agree wholeheartedly," responded Clarke. "We've had hearings already with that in mind. That's going to be a challenge in every corner of the nation because we're going to be expected to utilize the infrastructure that already exists. So there has

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Visibility Key as EVs Seek Growth Beyond Early Adopters

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technical conference on EVs in February. Saari said he and his colleagues are concentrating on four primary areas: customer education, rate design, the impact of EVs on the grid and charging infrastructure — "who is going to build what, where and how is it going to be priced out?"

Under the "make ready" model, the utility supplies the service connection and supply infrastructure, with the customer supplying the charging equipment. Another model would have the utilities assume full ownership of the charging equipment — the opposite of the business-as-usual model in which the customer is responsible for all equipment.

Saari said he expects both DTE Energy and Consumers Energy to request money for EVs in rate cases the companies will file later this year.

Lantrip said Southern Co.'s Georgia Power will propose several pilot projects to regulators later this year on getting EVs to low-income customers. "It could run the gamut from something like Zipcars or it could be electrified Ubers targeted in certain areas or something in between that," he said.

Lantrip called on utilities and regulators to be "creative in developing new rate designs."

Fisher said that although higher EV penetration will mean more electric demand, the grid investments required to expand the market are "going to turn out to be a wise ratepayer investment."

In California, which has more than 277,000 EVs — about half of the nation's total — a joint study by the state's three investor-owned utilities reported the costs of distribution upgrades to serve EVs have been "immaterial." But Southern California Edison has said 25% of its network must be upgraded to support new chargers.

Dan Adler, vice president of policy for the Energy Foundation, which promotes energy efficient buildings and appliances, said the industry needs "durable" coalitions to ensure regulatory policy does not become an obstacle to growth. "You get better policy outcomes … if the coalition is formed ahead of time," he said.

Role for Gas Stations

From the audience, D.C. Public Service Commission Chair Betty Ann Kane asked whether the industry was working with gas stations that might otherwise become "stranded investments" in an electrified transportation system.

"If you get the charging times down, there's an opportunity to work with that community," Adler said. Because gas stations make most of their profits from snack and beverage sales and not fuel, Adler said, station owners may welcome a new way to generate foot traffic.

Lantrip said new gas stations are increasingly being designed to be fit with electric charging. He said they may be the best locations for charging in urban areas where few residents own garages. Last October, Royal Dutch Shell announced it was buying one of Europe's largest EV charging providers; it is also beginning to add EV chargers at its stations in the U.K. and the Netherlands.

Institute for Electric Innovation Spring Forum

Overheard

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to be a collaboration. In many towns, cities, municipalities, there's going to be a struggle about how you site these things."

Corporate Renewable Procurements, Green Tariffs Growing

Letha Tawney, director of utility innovation for the World Resources Institute, led a panel discussion on corporate renewable energy procurements, noting that green tariff programs in 15 states have helped to bring 1 GW of new solar and wind projects to the grid since 2013.

"There's been some successes," said Tawney, whose organization works with utilities and customers to craft green tariffs. "How do we scale this? This is still pretty marginal. We just passed a gigawatt of transactions being signed. That's not that much, really, in the whole U.S. market. ... We need to do a lot more."

Robert M. Blue, CEO of Dominion Energy's Power Delivery Group, worked with customers like **Steve Chriss**, director of energy and strategy analysis for Walmart, in developing a new renewable generation (RG) tariff that functions as a contract for differences.

"The renewable generation tariff that we filed, a lot of it wasn't working for a lot of customers," Blue said. "That's why we revised it. We heard from them what would make it work better and we expect that that will have a substantial impact."

Last October, Dominion announced Facebook will build its eighth U.S. data center in the utility's territory outside Richmond, Va., under a proposed new Schedule RF (renewable facility) rate structure, with which the company will offset its 130-MW load with renewables. Facebook's goal is to power all its operations with renewable energy.

Walmart, which takes service from 1,000 utilities, has a goal of being 50% renewable power by 2025.

"We operate in a lot of states that aren't deregulated and a lot of states where there's not necessarily a market in place," said Chriss. "In SPP or MISO, you can do a virtual [power purchase agreement] ... but in Southern Co. or in some of the other big IOUs, there is no market, per se. So really, the market is their system and so you have to figure out structures that work within that."

Even within Southern's utilities, rules differ across state lines, Chriss said. "Our deal with Alabama Power [a 72-MW solar farm in southeastern Alabama that went into operation several weeks ago] ... is very different from the Georgia [Power] structure."

Nick Wagner, a member of the Iowa Utilities Board, discussed concerns over corporate procurements resulting in cost shifts to other customers.

"It's no secret to probably anybody in this room that utility costs have been so highly socialized for a long time. It will take us some time to unwind those as we have the data" from cost-of-service studies, he said. "It's probably a little more masked in the vertically integrated [states] than in the non-vertically integrated [states]. As we get more data, I think it's going to become a little bit easier to separate those things out."

Wagner said regulators' efforts are aided by interventions by customers and other interest groups. "If nobody's happy at the end of the day, but no one is really angry, you probably came to about the right place," he said. "If someone's walking out high-fiving, we know we messed up somewhere."

– Rich Heidorn Jr.

Transmission Summit East

Tx Summit Attendees Struggle to Define 'Resiliency' Problem

By Michael Brooks

WASHINGTON — Speakers and attendees at Infocast's 21st Transmission Summit East last week noted that "resiliency" was the buzzword of the event.

A consensus seems to have emerged on an industry meaning of the word that distinguishes it from "reliability": the ability to reduce the magnitude and duration of a disturbance in grid operations.

But there was little to no consensus on how regulators and utilities should measure or value it. Nor was there any agreement on whether there is even a resilience problem to solve.

Michael Spoor, vice president of transmission for Florida Power & Light, opened the conference with a presentation detailing how the utility's hardening of its system lessened the impact of last year's Hurricane Irma compared to Hurricane Wilma in 2005. Since 2006, FPL has spent more than $3 billion to replace its wooden transmission and distribution poles with concrete and steel structures able to withstand 145-mph winds, as well as undergrounding some of its lines.

Despite Irma making landfall in Florida as a Category 4 storm (compared to Wilma's Category 3) and affecting 1.2 million more customers than Wilma, it took eight fewer days for FPL to restore service to its customers.

But that was a case of a utility in a non-RTO state taking the initiative itself, without market-based incentives or federal directives.

"This isn't a new problem. We're using a new word, maybe, to define something that we've doing for a really, really long time," **Katherine Prewitt**, vice president of transmission for Southern Co., said in a Wednesday panel on valuing resiliency.

"I think that the bottom line with regard to the word 'resiliency' has a lot more to do with policy and politics than it does with operations and what we're doing on the ground," said **Barbara Clemenhagen**, vice president of market intelligence for Customized Energy Solutions. Utilities have been complying with NERC reliability standards on a nonvoluntary basis, "but certainly I don't think there's any utility in the room who would say they wouldn't volunteer to address all of these standards."

Paul Kelly, director of federal policy for Northern Indiana Public Service Co., noted that a NERC report published last year found that resilience against weather-related events has been improving. "So there wasn't so much of an alarm bell being sounded from the reliability organization, but nationally it's become a very politically focused issue.

"We really want to make sure we make the right decisions, and that we have a really good understanding of 'is there truly a problem?'"

'Beyond N-1'

The concept of N-1 — planning for the loss of a grid asset, such as a generator or a transformer — has "served us well for over 100 years," **Mohammed Alfayyoumi**, director of Dominion Energy's transmission system operations center, said in a panel on considering resiliency in grid planning. "But in today's environment with a focus on resilience, I think we need to go beyond N-1, where we can look at N-2, N-5, depending on the situation." Technology has progressed so that computers can calculate N-2 across the system, he said.

Paul McGlynn, PJM senior director of system planning, said natural gas pipelines are also important for resilience. "We need to expand [N-1 contingencies] to events on the pipeline system: loss of a pipeline, loss of compressor station or whatever may also impact part of your generation fleet."

But Clemenhagen said there was a need for

Michael Spoor, Florida Power & Light | *© RTO Insider*

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Transmission Summit East

Tx Summit Attendees Struggle to Define 'Resiliency' Problem

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From left to right: John Lawhorn, MISO; Keith Collins, SPP; and Vincent Duane, PJM. | *© RTO Insider*

discussion on "the difference between a rational economic system that makes sense for … the consumers who are paying for it and, not just a gold-plated system, but a platinum-plated system that you hear some policymakers assume that we can have; not just N-1 but N-∞ contingencies."

A former member of the British Columbia Utilities Commission, Clemenhagen said, "We need to be very careful to define [resiliency] … based on rational economics for consumer interests, because in the end, they have to pay for it. The end users are the ones who pay; I don't care how you calculate it, whether it's market-based costs or reliability-based costs, consumers will pay for these costs in the end."

"We could platinum-plate the system, but I don't think that's what anyone wants," Prewitt said.

"'The ability to rapidly recover' … looks a lot different in Louisiana that's recovering from a hurricane event, than it does in my state of Indiana if we have an ice storm in the dead of winter," Kelly said. "I think our standards in America are phenomenal because we emphasize reliability. And if I could take a dollar and invest it somewhere, I'd much rather invest it in reliability. I'd rather keep the lights on for my customers versus taking that dollar and shipping it over to resilience."

Why Now?

Several moderators asked their panelists why resiliency was such a big focus of discussion lately — and each gave a somewhat different answer.

McGlynn talked about the threat of bad actors and cyberattacks. **Aubrey Johnson**, MISO executive director of system planning and competitive transmission, cited the reliance on electricity for almost every aspect of modern life, and that people are more aware of outages across the country. Alfayyoumi said that the grid is becoming more complex because of the rise of renewable resources. Clemenhagen, along with many other panelists and attendees, cited recent severe weather events across the country.

Barely mentioned, however, was Energy Secretary Rick Perry's proposed Grid Resiliency Pricing Rule, which called for RTOs to pay the full operating costs for generators with 90-day onsite fuel supplies. In testimony before Congress, Perry cited the polar vortex of 2014 as evidence for the rule's need. (See *Perry Defends Call for Coal, Nuclear Supports*.)

However, the proposal was apparently based on an "action plan" from coal producer Murray Energy that called for "immediate action … to require organized power markets to value fuel security, fuel diversity and ancillary services that only baseload generating assets, especially coal plants, can provide." (See *Photos Show Murray's Role in Perry Coal NOPR*.)

FERC eventually rejected the proposal, instead opening a new docket to document how each RTO and ISO assesses resilience and use the information "to evaluate whether additional commission action regarding resilience is appropriate." The summit came on the eve of the due date for the grid operators' responses. (See related story, *RTO Resilience Filings Seek Time, More Gas Coordination*, p.1.)

"Resiliency means different things to different people," John Lawhorn, senior director of policy and economic studies for MISO, said in a Thursday panel on the status of wholesale market reforms. "From my personal perspective, I think the risk associated with overbuilds is much less than the risk associated with underbuilds. But we need to be able to quantify that information for presentation to our stakeholders and our regulators to have them weigh in to evaluate how much risk they want to take."

"There are different ways to address [resiliency], but the definition of what it is and how you solve that and measure it, from my perspective, is very important," said Keith Collins, executive director of SPP's Market Monitoring Unit.

"I don't know what FERC's going to do with this," PJM General Counsel Vince Duane said, sounding almost weary. "They're going to have a tremendous amount of information, and it's going to be leading in a lot of different directions, so I don't envy their task. And it's hard to offer tangible and concrete suggestions, but at PJM we've tried to do that in our comments tomorrow as best we can."

FERC is "going to have a tremendous amount of information, and it's going to be leading in a lot of different directions, so I don't envy their task."

Vince Duane, PJM

Transmission Summit East

Overheard

WASHINGTON — Transmission developers, planners and regulators gathered last week at the Washington Marriott Georgetown hotel for the three-day Infocast Transmission Summit East. While grid security was on the minds of all who attended, speakers also had plenty of opportunities to vent about FERC Order 1000 and RTO planning processes — as well as poke fun at Ted Koppel.

"Because we're focused on the resiliency component — and then we're specifically focused on critical infrastructure — … the market actually has no place in making the determination for those investments."

Bruce Walker, DOE

DOE Official Briefs 'North American Model'

Bruce Walker, assistant secretary of the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy, briefed attendees Wednesday on five initiatives by the department to enhance grid security.

The most ambitious, by the department's Grid Modernization Lab Consortium, is developing a "North American all-energy systems model" that includes all the grid operators across North America and identifying their interdependencies.

"Once we've got this model, we'll be able to do real-time analysis [and] next-worst-case analysis, so when an excursion occurs on any one of the major systems in the United States or Canada or Mexico, we'll be able to run it and understand what that means and what the next-worst piece of equipment or system is to lose, so that we can proactively act to prevent that, whether it's providing physical security, whether it's changing the load flows on the grid to lessen the load or demand in one particular place," Walker said. Many of these actions would be taken by RTOs, he said.

The model will be so comprehensive, he said, that it will be able to do "N-K" load-flow analysis, with the "K" standing for assets that aren't traditionally considered part of the electric grid. (See related story, "Beyond N-1," *Tx Summit Attendees Struggle to Define 'Resiliency' Problem*, p.7.)

Another initiative is "megawatt-scale storage strategically being utilized throughout the grid." Walker said this initiative ties in with the North American Model, which will allow the department to "identify where the best investments of these" storage assets would be.

This raised the eyebrow of Rob Gramlich, president of Grid Strategies. "'Identifying best investments': that sounds like a market function. How does this initiative interact with the market?" he asked.

"Because we're focused on the resiliency component — and then we're specifically focused on critical infrastructure — … the market actually has no place in making the determination for those investments," Walker responded. "So part of why we got FERC, NERC and DOE looking at the system and building this model is we come at it from slightly different angles. FERC's angle is a bit more market-driven; NERC's is more reliability-driven; DOE has got very specific requirements, being the sector-specific agency for cybersecurity in the energy industry, focusing in on critical infrastructure throughout the United States."

From left to right: Mark Scott, D.C. Homeland Security Emergency Management Agency; Michael D. Melvin, NIPSCO; Col. Victor Macias, National Guard; Ralph King, EPRI; Michael Garcia, National Governors Association; and Brian Harrell, George Washington University. | © *RTO Insider*

Impact of Ukraine-style Attack Would be Less

A cyberattack on the U.S. grid by a foreign power such as the one experienced by Ukraine in 2015 and 2016 is certainly possible, several experts said in a Wednesday panel on cybersecurity.

But Ukraine lacks the basic protections and infrastructure of the U.S., meaning such an attack would be far less disruptive and destructive here, they said.

Or as moderator Brian Harrell, senior fellow at George Washington University's Center for Cyber and Homeland Security, quipped, "I don't know too many utilities here in the United States running pirated versions of Windows XP on their systems. So, there are some differences here."

The general consensus among the panel,

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Transmission Summit East

Overheard

Continued from page 9

which included a National Guard colonel, was that utilities need to be incentivized to do more than the minimum required by NERC, as well as be on guard for insider threats.

But the panelists unanimously labeled as off-base the assertion made by broadcast journalist Ted Koppel in his book "Lights Out" — the mention of which drew laughter from the audience — that the U.S. is susceptible to a catastrophic attack and that industry and government are not taking the threats seriously.

From left to right: Kamran Ali, AEP; Barbara Clemenhagen, Customized Energy Solutions; Jack McCall, Lindsey Manufacturing; and Ed Tatum, American Municipal Power. | © RTO Insider

Flaws in Planning Processes

Many speakers complained about the transmission planning processes in RTOs, including the competitive and interregional processes.

On a Thursday panel discussing the effects of renewable energy resources on transmission planning, Invenergy Senior Vice President Kris Zadlo said he doesn't "think transmission planning is happening."

"Operating lines that [are] 2% overloaded or replacing transformers: that's not transmission planning," Zadlo said. "That's asset management."

He pointed to American Electric Power's Wind Catcher Energy Connection Project, which Kelly Pearce, director of contracts and analysis for the company, had briefed attendees on earlier in the day. The project would be the largest wind energy facility in the U.S at 2 GW, with a dedicated 765-kV tie line from the Oklahoma Panhandle to Tulsa.

"Folks are trying to find end-arounds," Zadlo said. Wind Catcher is a "360-mile end-around because SPP's transmission planning process has failed. … Quite frankly it's disgraceful that we have to wait three to five years for an interconnection study to be processed by utilities and by ISOs."

Kip Fox, president of Electric Transmission Texas, said, "One thing we do notice across all of the RTOs that everybody should kind of think about is we're not seeing a lot of interregional" projects. "We are not seeing projects that are going across RTOs. And unfortunately, that's where the big bang for the buck economically is going to be. And usually I find it's a fight over who's going to pay for that project, rather than whether that project makes sense."

On a separate panel Thursday, Kamran Ali, AEP vice president of grid development, noted that between 2012 and 2016, PJM identified 72 projects that were open for competition. Of those, only three ended up being assigned to nonincumbent utilities, he said.

Trump Admin's Effects?

"Have you guys polled the millennials as to what their feelings and thoughts are regarding renewable energy? If you haven't, you better."

Kris Zadlo, Invenergy

Speakers at the conference uniformly dismissed the actions of the Trump administration as having any effect on the growth of renewables and the retirement of coal-fired generation. Even as one attendee announced to the conference that President Trump had imposed tariffs on steel and aluminum imports Thursday afternoon, panelists were not concerned.

"There's something interesting that's going to happen in 2020," Zadlo said. "It's not that the [production tax credits] are going to run out." Nor is it the next presidential election year. "In 2020, millennials will be over 50% of the workforce. Have you guys polled the millennials as to what their feelings and thoughts are regarding renewable energy? If you haven't, you better. Because they want it."

— Michael Brooks

| © RTO Insider

CAISO News

EIM Governing Body Approves CAISO Bidding Flexibility

By Jason Fordney


The EIM Governing Body meets on March 8. | © RTO Insider

LOS ANGELES — Western Energy Imbalance Market (EIM) leaders last week endorsed CAISO's controversial proposal to give generators more bidding flexibility, but not without giving ground to the plan's skeptics.

The EIM's Governing Body on Thursday approved the ISO's Commitment Costs and Default Energy Bid Enhancements (CCDEBE), designed to give generators more latitude in how they reflect their commitment — or start-up and minimum load — costs and overhaul the way the ISO calculates the default energy bid, which replaces bids of units found to have market power.

The current method can artificially limit a generator's commitment cost and limits what the generator can bid in, the ISO has said.

But to the end, market participants and the ISO's Department of Market Monitoring raised questions after a lengthy stakeholder process to develop the rules. (See CAISO Developing New Bidding Rules.)

The rule changes still require approval by the CAISO Board of Governors, which will consider the proposal at its March 21-22 meeting.

'A Good Place'

CAISO's proposal replaces a static commitment cost bid cap with a local market power mitigation test, which identifies whether a resource needs to be committed to relieve a transmission overload or other constraints, the same way energy bids are handled. The ISO will only mitigate bids when a generator fails the test.

Under the current rules, the ISO calculates reference levels for each gas-fired generator based on published natural gas price indices. The commitment cost reference level is determined by multiplying costs by 125% and bids are capped at the generator's reference level.

CAISO plans to phase in commitment cost bidding flexibility, first raising the commitment cost multiplier to 150% for the first 18 months after implementation, and then increasing it to 300% if no issues arise.

During the rulemaking process and at Thursday's meeting, there was heavy debate over CAISO's plan to automatically increase the reference levels after 18 months. Some commenters, such as Governing Body member Kristine Schmidt, suggested that a new stakeholder process might be needed at the 18-month point.

But CAISO Vice President of Market and Infrastructure Development Keith Casey resisted the idea, saying "it sends a message to the market that we are not serious about this."

Body members compromised by adding a provision to the decision that the ISO provide a status report to the EIM and CAISO board at the 18-month point.

"This was tough one, but I think we ended up in a good place on this," Governing Body Chairman Douglas Howe said.

The ISO recently lowered the proposed multiplier for the first 18 months to 150% from 200%, in an "abundance of caution," Market Design Manager Brad Cooper said, calling the bid cap a "circuit breaker." The proposal also allows suppliers to seek adjustments to their reference levels based on changes in documented costs.

"We believe that we have a robust design, but we agree we need to proceed cautiously with changes," Cooper said during a presentation to the Governing Body.

Respectful Disagreement

DMM Director Eric Hildebrandt supported the proposal, saying "the basic framework is there." But he recommended a few changes, saying there are some gaps, a potential for economic withholding and for a "kind of gaming." (See *Monitor Critical of CAISO Commitment Cost Mitigation Plan*.)

"We have looked at it, and we respectfully disagree," Casey responded, adding that some power suppliers are "sort of biting their tongue" on the arrangement for the first 18 months. An automatic change at the 18-month point provides certainty that the ISO is committed to moving to the higher cap, he said, adding that CAISO can always file with FERC to keep the level at 150% if it discovers issues.

Howe said the EIM's decision "is trying to carve a middle road," but he didn't think CAISO should "back into" a second stakeholder process that would "allow everybody to have a second bite" at things they didn't like.

Body member John Prescott said, "I support this, and I would advise the Board of Governors to support this as well." He said he expects the DMM to make sure issues don't materialize.

Representing the Western Power Trading Forum, Carrie Bentley of Resoro Consulting told *RTO Insider* that the parties most affected by the change will be EIM entities or others who have experienced challenges with CAISO calculating their proxy costs, and generators and scheduling coordinators impacted by high gas prices.

She said that while WPTF supports the proposal, she called CAISO's changing the reference level late in the proceeding "an unfortunate circumstance of panic policymaking in response to a few influential stakeholders. The CAISO had an excellent proposal, and it would have been better if they just remained confident in it."

CAISO NEWS

Picker Seeks Guidance on IOUs, Aliso Canyon

By Jason Fordney

California Public Utilities Commission President Michael Picker last week asked state lawmakers for guidance on the increasingly precarious financial health of the state's investor-owned utilities, which face growing risks stemming from wildfires.

That topic — and reliability concerns surrounding the Aliso Canyon gas storage facility — dominated discussion at a hearing of the State Senate Energy, Utilities and Communications Committee in Sacramento.

Committee Chairman Ben Hueso (D) said that "there has been one issue over another" affecting utility planning and operations, including earthquakes, floods and wildfires.

"There has always been something that complicates the ability of the state of California to provide energy to the people of the state," Hueso said.

Picker noted that analysts had recently downgraded the credit rating of a solar project owned by an independent power producer because it holds a contract with a utility, showing the ripple effect of utility credit downgrades that have occurred recently over wildfire risk. The trend could make it more difficult for California to meet its greenhouse gas reduction goals, he said.

"If this continues, we will probably have a hard time saying to the rest of the world that we could accelerate the process of greening the grid," Picker said.

Several IOUs have recently been downgraded or placed on credit watch by ratings agencies, leading to worries in Sacramento about a repeat of the California energy crisis of 2000-2001 and IOU bankruptcies.

The State Assembly recently held its own hearing on the issue, at which Picker also spoke. (See Wildfire Costs Ignite Worry at CPUC, Legislature.)

"I see the exact same pattern with respect to the investor-owned utilities that we have seen before," said Sen. Robert Hertzberg (D), adding that credit downgrades can cause "cross-defaults" and other complications.

"The rate at which this thing falls apart is extraordinary," Hertzberg said. "The house of cards is impacted in a way that is not quite positive."

Picker has repeatedly asked lawmakers for direction on the issue.

"I am not here to tell the legislature what to do," Picker said last Tuesday. "I agree that it

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CAISO NEWS

'Hesitancy' Around Western RTO, EIM Chair Says

Continued from page 1

RTO," Howe said. "The idea of transmission allocation and a uniform transmission price across a region as big as the Western Interconnection gets a lot of people a little nervous, because we have widely varying transmission costs in the West."

Several possible changes are stirring the West, including a joint proposal by Peak Reliability and PJM to create a new market and CAISO's plan to extend its day-ahead market across the EIM. (See *Peak Touts 'Independent' Western Market Plan* and *CAISO Plan Extends Day-Ahead Market to EIM*.) There is also California legislation underway that could regionalize CAISO. (See *Calif. Lawmakers Relaunch CAISO Regionalization*.)

While the Peak/PJM market proposal only sets out to establish an energy market, and not a full RTO, Peak executives have described it as a "pathway" to an RTO.

"All of these initiatives are in some sense a pathway to an RTO," Howe said. The question is how to deliver the benefits of an RTO, such as day-ahead, real-time and ancillary services markets, "without triggering all this anxiety," he said.

The best approach, according to Howe?

"Let's get the energy markets established first and then we will see where stakeholders are comfortable going."

Howe said industry participants have several choices to examine now and will be analyzing the costs and benefits of each one, "and whether it has sufficient bells and whistles — is it the right market to be in?"

One concern is "the absence of a real exit strategy" if a market participant joins an RTO, he said.

"If you find it's not working out for you, getting out is extraordinarily expensive," Howe said. While CAISO is seeking to extend the day-ahead market across the EIM, an RTO "is not what we are proposing at this point." The trade-off is that participants don't get the full benefits of an RTO either, he said.

When asked about whether there is unease about a balkanized and noncontiguous market taking shape, Howe said, "I don't think there is a lot of concern about that." The Eastern U.S. is balkanized to some degree and "it's a spider web of transmission," he said. In the West, transmission lines run north and south and east and west from the coast inland.

"They have worked that out in the East, but there is some concern that the West is not the same as the East, and that is going to be part of the working-out process," Howe said. "There might be a little more concern about the reliability coordinator becoming balkanized, because they are the ones that have a high-level view of the entire grid."

Picker Seeks Guidance on IOUs, Aliso Canyon

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is urgent, but I do tend to work at the direction of the legislature."

Elected officials have publicly discussed new legislation on the issue of "inverse condemnation," a legal provision that allows utilities to seek recovery of wildfire-related costs in regulatory proceedings. The state's three IOUs have banded together to challenge a recent CPUC decision denying cost recovery for San Diego Gas & Electric for damages from a 2007 fire, despite the utility's reliance on the provision. (See *Sempra Joins 'Three-Pronged' Wildfire Front*.)

Stern Objects to Aliso Canyon Decision

During the hearing, Sen. Henry Stern (D) vocalized his displeasure with a March 3 decision by CPUC Energy Division Director Edward Randolph that the legislator said "secretly granted" a Southern California Gas request for "immediate, seemingly open-ended utilization of the Aliso Canyon underground storage facility."

In a March 5 letter to the commission, Stern asked questions about the status of gas pipelines taken out of service this winter and how those decisions were made. Stern, whose district includes Porter Ranch, the site of numerous local health complaints attributed to the facility, has called for Aliso Canyon's closure.

But Aliso Canyon is also central to California's electric reliability, leading CAISO to implement special measures to mitigate concerns about gas supplies to generators. (See *Gas Adders a Necessary Tool, CAISO Says* and *CAISO Board Approves Aliso Canyon Rules Package*.)

Stern said when there is a "Saturday night letter from Ed Randolph" that becomes public, "it starts to corrode that public trust."

"We want to see this public trust restored, and it's just not there right now," Stern said. "People are going to assume the worst."

Picker responded that he had recently proposed a moratorium on new commercial gas hookups in the Los Angeles County area that met heavy resistance from the business community. At its most recent meeting, the commission withdrew the proposed agenda item.

Picker said that "there is a core denial" of gas supply concerns and that "I need your help to get through that." The real need for gas units is peaking power, he said.

"I completely agree there is plenty of blame to spread around here," Stern said.

Picker also briefly sparred with Sen. Mike McGuire (D), who objected to Picker's recent public suggestion that ratepayers in high-risk fire zones pay more for electricity. Picker used the example of homeowner's insurance premiums in those areas that are higher based on fire risk.

McGuire, a Democrat from the North Coast district, which includes Marin County, replied that many of the fires occurred in areas without heavy tree growth.

"I will fight it with every bone in my body," McGuire said of Picker's proposal.

Picker and CPUC staff recently sent the commission's 2017 annual report to the legislature, along with the Office of Ratepayer Advocates report.

CAISO NEWS

RTO Resilience Filings Seek Time, More Gas Coordination

Continued from page 1

Economic pressure on natural gas plants in CAISO has led to reliability payments for Calpine's Yuba City Energy Center. | © *RTO Insider*

CAISO, meanwhile, criticized FERC's definition of resilience as "somewhat vague."

Other parties will have 30 days to respond to the RTO's filings, although one coalition filed comments earlier last week. (See *Coalition Targets Capacity Markets in Resiliency Docket*.)

CAISO Says Resilience Order 'Vague'

CAISO's comments reflected its changing resource mix and unique circumstances compared with other RTOs, but the grid operator questioned the meaning of the term "resilience."

"The CAISO notes that the concept of 'resilience' presented in the resilience order is general and somewhat vague. It includes no clear objective criteria, metrics or standards to evaluate whether the existing grid is resilient," CAISO said in comments signed by General Counsel Roger Collanton and other attorneys.

The order also lacks cost-benefit analysis, financing concerns or "prudence assessment," CAISO said, adding that current reliability standards address many similar issues.

While the ISO criticized aspects of the order, it did detail some challenges it faces, noting that the growth of renewables has put economic pressure on the gas-fired fleet through factors such as the inability to attain resource adequacy contracts and competition for flexibility services such as ramping.

Earthquakes, drought and wildfires are the unique risks facing California, CAISO said in its 176-page filing. It also cited as risks cyberattacks and the closure of the Aliso Canyon gas storage field and the San Onofre nuclear power plant.

There are no baseload coal units in the CAISO balancing area, and the last remaining nuclear plant, Diablo Canyon, is set to retire in 2024. With natural gas generation declining and the system rapidly transitioning to renewables, in part because of the massive expansion of rooftop solar, CAISO has surplus power in daylight hours, resulting in curtailments and ramping needs illustrated by the "duck curve."

The grid operator said that entities other than RTOs also have a role in providing resilience, such as transmission and generation owners, fuel suppliers, federal and state agencies, environmental groups and others.

CAISO said it did not see a need for an additional requirement for RTOs/ISOs to identify resilience needs as proposed in the order, for multiple generation outage scenarios, fuel disruptions and other events. Analyzing "common-mode" impacts is appropriate and addressed in normal utility reliability planning, it said.

"Creating a new risk-based analysis requirement would likely be overly prescriptive, difficult to clearly define and likely duplicate existing reliability standards given the wide range of varying specific risks different ISOs and RTOs face," it said.

CAISO said its sensitivity analyses indicate 1,000 to 2,000 MW of retirements could result in shortfalls in load following and reserves after sunset when rooftop solar goes offline. It is supporting multiyear resource adequacy requirements for local capacity resources instead of one year and changing its backstop procurement programs.

The ISO has a filing with FERC regarding its capacity procurement mechanism and reliability-must-run changes, the topic of heavy debate in stakeholder discussions. The ISO's internal market monitor has filed a protest to the proposal. (See *CAISO, Stakeholders Debate RMR Revisions*.)

Studies that CAISO has conducted include gas-electric coordination planning studies for both Southern and Northern California, as well as frequency response studies related to the replacement of conventional thermal resources with renewables, storage and distributed energy sources. Special reliability studies are done during the transmission planning process.

The grid operator added that the question as to whether the grid could "reasonably withstand" high-impact, low-frequency events was not defined and is difficult to respond to.

CAISO asked for a "a holistic approach that also considers the unique circumstances and conditions facing each region" as the resilience criteria is considered.

— Jason Fordney

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CAISO NEWS

PGE, BPA Sign 5-Year Hydro PPAs

By Robert Mullin

Portland General Electric (PGE) and the Bonneville Power Administration said Wednesday they have signed two agreements that will help PGE avert a generation shortage after it shuts down its coal-fired Boardman Generating Station in 2020.

PGE in 2010 agreed to close the 550-MW Boardman plant to avoid investing the $470 million in pollution controls needed to keep Oregon's last coal-fired generator running until its original 2040 retirement date. The utility last year halted efforts to build two new gas-fired plants at the Boardman site, saying it was instead pursuing talks to obtain existing resources.

Wednesday's announcement revealed those resources will be supplied by BPA, which will sell the Oregon utility up to 200 MW of surplus hydropower from the Federal Columbia River Power System under two concurrent five-year power purchase agreements for two different energy products, starting in January 2021. BPA told *RTO Insider* it could divulge only limited details about the contracts because they are subject to a non-disclosure agreement.

"That said, we can say that the two products are an advance notice right to power, each with different notification timeframes," BPA spokesman David Wilson said. "Each product also carries asset-controlling supplier status," which allows the associated energy to be exported to California with a low emissions factor for the purpose of greenhouse gas reporting under that state's cap-and-trade program.

BPA said there were benefits to both parties in the deal, with PGE gaining access to fast-ramping resources while the federal power marketing agency pursues one plank of its recently announced strategic plan, which includes the marketing of "competitive products and services."

"In addition to allowing BPA to take advantage of a new opportunity to market its clean, flexible hydropower and generate direct revenue as part of a broadening portfolio of power products, the contracts allow PGE more time for new dispatchable resource technologies to mature to help the company integrate increasing amounts of renewable power onto its system," BPA said.

"These agreements are a great opportunity for us to collaborate with BPA to achieve shared goals in the region," said PGE CEO Maria Pope.

The deal also has found support among key ratepayer and environmental advocates in the region.

"This is a great deal for the region. It's a value-added product for the federal power system and a good alternative for PGE. It puts off big new investments in gas that would have locked PGE and its customers into fossil fuels for decades," said Bob Jenks, executive director of the Oregon Citizens' Utility Board.

"Instead of building new carbon-emitting resources, PGE is able to take advantage of existing clean hydropower, and BPA is able to lock in a future sale to help strengthen its financial health," said Wendy Gerlitz, policy director with the NW Energy Coalition.

The power that PGE acquires under the BPA contracts will not count toward Oregon's 50%-by-2040 renewable portfolio standard, which bars facilities that began operating before 1995. But it will contribute to the utility's efforts to meet an Oregon requirement to reduce emissions to 80% below 1990 levels by 2050.

PGE earlier this month circulated a draft request for proposals seeking 100 MW of renewable power to help meet both those mandates. The utility expects to bring those resources into its portfolio by 2021.

The utility last October joined Western Energy Imbalance Market (EIM), drawing $2.8 million in net benefits during its first three months of participation, according to CAISO.

ERCOT NEWS

Texas PUC Approves Sempra-Oncor Deal, LP&L Transfer

By Tom Kleckner

AUSTIN, Texas — Texas regulators quickly dispensed with two multiyear cases before them Thursday, clearing the way for Sempra Energy to acquire Oncor and for Lubbock Power & Light to migrate from SPP to ERCOT.

The Public Utility Commission made only minor revisions to the Sempra-Oncor order and added several tweaks to the LP&L order, spending more time during its open meeting congratulating those involved in the two proceedings.

PUC Chair DeAnn Walker recalled attending the National Association of Regulatory Utility Commissioners winter meetings, where she heard a financial analyst say, "What's best for us is when a utility commission speaks, they stick to what they have asked."

"This commission and the intervenors spoke at least twice, maybe three times in the preliminary order, on what their expectations were to get things done," Walker said, referring to the Sempra-Oncor settlement agreement with all intervenors in its application (Docket No. 47675). "Sempra listened to that and came forward and did that. I think it speaks for y'all and it speaks for the commission that we have now stuck to what we said we were asking for."

Oncor 'Saves Best for Last'

The PUC's approval of Sempra's acquisition of Energy Future Holdings' 80.03% interest in Oncor all but seals the California-based company's pursuit of Texas' largest electric utility. Sempra has already received approval from FERC and the U.S. Bankruptcy Court for the District of Delaware, where EFH filed for bankruptcy in 2014. (See *Bankruptcy Court OKs Sempra-Oncor Deal*.)

Sempra has succeeded where others failed. Its $9.45 billion all-cash bid for Oncor caught Warren Buffett's Berkshire Hathaway Energy off-guard in August, while Hunt Consolidated and NextEra Energy saw their acquisition attempts fall apart before the PUC.

"We clearly saved the best for last with Sempra," Oncor spokesman Geoff Bailey told *RTO Insider* outside the PUC's hearing room. "We've got a four-year process behind us, and we're ready to move forward into the future. I think I speak for all Oncor employees when I say it's an exciting day for the company. We're excited to get everything behind us."

"We appreciate the commission's support throughout this long, four-year process to find a new majority owner for Oncor," Oncor CEO Bob Shapard said in a statement. "We believe this is an excellent outcome for our company, our customers and our employees. Sempra Energy is a well-run company, and we believe they will be a strong, stable majority owner for Oncor and an excellent partner for Texas."

Headquartered in San Diego, Sempra is a Fortune 500 company with 16,000 employees and about 32 million consumers around the world. The company earned more than $11 billion in revenue last year.

Oncor operates the largest distribution and transmission system in Texas, delivering power to more than 3.5 million homes and businesses while operating more than 134,000 miles of lines.

Sempra CEO Debra Reed said she was pleased the commission found the transaction to be in the public interest.

"Sempra Energy is committed to being a good partner for the state and is supportive of Oncor's mission to provide Texans with safe, reliable and affordable electric service," she said.

In reaching an agreement with various consumer groups before the PUC, Sempra agreed to employ strict ring-fencing measures that include an independent board of directors, to extinguish EFH's debt and to pass tax savings on to Oncor customers. (See *Sempra, Oncor Reach Agreement with Texas Intervenors*.)

Shapard and General Counsel Allen Nye will both retain positions on the post-acquisition board of directors as chairman and CEO, respectively.

"You can't get your fancy pants on now that you are going to be CEO and think you're too big for us," Walker told Nye. "You have to come visit us and see us from time to time. I know you have a company to run, but this is a regulated industry, and guess what we do."

"I've had the distinct pleasure of being here almost 25 years now, and I have no intention of going away," Nye responded. "This place means the world to me. You can get used to seeing me."

Sempra will fund the purchase through of combination of about 65% equity and 35% long-term debt. It said in a letter to the PUC that it intends to acquire Oncor Management Investment's 0.22% interest in Oncor when or after the transaction closes.

Should Sempra pursue the remaining 19.75% interest in Oncor held by Texas Transmission Investment, it would need to secure the commission's approval and adhere to the same regulatory commitments to which it has already agreed.

Sempra said that the transaction "remains subject to certain customary closing conditions" and that it expects to wrap it up "shortly."

Bailey promised that Oncor's customers "will see no changes and not be impacted by this transaction."

LP&L Welcomed into ERCOT

"Welcome to ERCOT, hopefully," Walker said to Lubbock Mayor Dan Pope after the commission approved a draft order allowing the city's utility to join the ISO (Docket No. 47576). "It is by far the best ISO/RTO in the United States."

Speaking to the media minutes later, Pope agreed with Walker as he called it a "big

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Lubbock Mayor Dan Pope | © *RTO Insider*

ERCOT NEWS

Marquez to Depart Texas PUC

AUSTIN, Texas — Texas Public Utility Commissioner Brandy Marty Marquez quietly resigned Thursday, saying she will pursue life in the private sector after two decades of public service.

Her resignation is effective April 2.

The announcement came several hours after the PUC's open meeting. There was little hint of what was to come during the meeting, other than when Chairman DeAnn Walker, a close friend of Marquez, choked up in announcing the commission was going into a closed session to "deliberate personnel matters." Walker avoided looking at Marquez as she gathered her composure.

"Is that it? Can we go?" Marquez said, smiling broadly. She had already met separately with Walker and fellow Commissioner Arthur D'Andrea before the open session to tell them of her decision.

Marquez's resignation will mean the three-person PUC has completely turned over since last May, when longtime Chair Donna Nelson left. Her departure was followed by that of Ken Anderson, who resigned after his term expired in August. They were the two longest serving commissioners in PUC history, each having served eight years or more.

Marquez was appointed to the commission in August 2013 by then-Gov. Rick Perry and reappointed by Gov. Greg Abbott in 2015. Her term was to expire in September 2019.

She said in a statement she leaves the commission knowing it will continue to serve Texas "with fairness under the principled leadership" of Walker and D'Andrea.

Left to right: PUC Commissioners Brandy Marty Marquez, Chair DeAnn Walker and Arthur D'Andrea. | © RTO Insider

"Supported by the best staff of any Texas agency, the PUC will continue working tirelessly on behalf of stakeholders and consumers," Marquez said. "I am honored to have served my fellow Texans. I leave with a happy heart."

Despite speculation that she would return to the political arena, Marquez said she plans to enter the private sector. She served as Perry's policy director during his successful 2010 gubernatorial campaign and was his chief of staff during Texas' 83rd legislative session. The Legislature next meets in January 2019.

"The state of Texas has benefited greatly from the more than 17 years of dedicated service from Brandy Marquez," Abbott said. "Her commitment and passion for public service have been on full display throughout her impressive career. I commend Brandy for her extraordinary accomplishments during her tenure as commissioner."

While at the commission, Marquez also served on the Texas Reliability Entity, which serves as the PUC's reliability monitor for the ERCOT region and enforces NERC standards.

Commission Directs ERCOT to Revise ORDC

The PUC directed ERCOT to begin the process of removing reliability unit commitment (RUC) capacity from the ISO's operating reserve demand curve (ORDC), which creates a real-time price adder to reflect the value of available reserves and is meant to incentivize resources to produce more energy and reserves (Project No. 47199).

Marquez said her preference was to wait until after the summer, when operating reserves are expected to be tight, but she

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Texas PUC Approves Sempra-Oncor Deal, LP&L Transfer

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day."

"In some ways, this is pretty historic," he said, noting Lubbock is the largest municipality to join ERCOT in almost 25 years. Pope said the key reason the city decided to join the ISO's open-access market is because "it is the most efficient, competitive energy grid in the country, and it provides the most choice."

LP&L announced in 2015 that it intended to move about 70% of its load from SPP to ERCOT. The city's power needs are currently met through two long-term contracts with Southwestern Public Service, one of which expires in June 2021, LP&L's target date to join ERCOT.

LP&L has agreed to pay $22 million annually over five years to compensate ERCOT's transmission customers for additional infrastructure costs and to make a one-time $24 million payment to SPS for previous infrastructure costs. (See *PUCT Nears Approval on LP&L Move to ERCOT*.)

The PUC directed LP&L to work with Sharyland Utilities — which has proposed a $247.5 million, 345-kV project that overlaps with the facilities necessary to integrate Lubbock's load into ERCOT — to coordinate their responsibility for respective parts of the system. Lubbock must also determine how to extend customer choice to all its customers.

Pope said the city and LP&L are already working on interconnecting with ERCOT and giving all its customers a competitive option. "Ideally, all of our citizens have to have that ability to opt in," he said.

Speaking for SPP, General Counsel Paul Suskie said the RTO recognizes that membership and participation is voluntary.

"Entities have the ability to make decisions they believe are best for their organization and their customers, which Lubbock has done in this situation," Suskie said.

ERCOT NEWS

Marquez to Depart Texas PUC

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joined with Walker and D'Andrea in the decision.

"I think taking out the RUC is the right thing to do," Walker said. "I don't think it's going to make a significant difference for the summer, but it sends the signal we're fully supportive of the energy-only market, and we will stand behind it.

"I want to be clear that this decision is based on what I believe is the correct decision, and not because anyone has made me believe this," she continued. "I've been there a long time, and I didn't need help getting there."

"I can't envision anybody … who believes in this market that wouldn't support this change," Marquez said. "We've never gone into a summer like this. It will be an incredible learning opportunity for our market. Anything we're preparing for now will potentially look very different after August."

PUC staff have also recommended removing the RUC and reliability-must-run capacity from the ORDC, saying it would ensure that scarcity pricing is accurate and reflective of market dynamics. Some market participants have pushed back, sharing Marquez's view that it would be best to wait until after the summer to make the change. (See "Participants Caution Against Market Changes Before Summer," *Overheard at the Infocast ERCOT Market Summit*.)

ERCOT staff filed a report with the PUC on March 2 that indicates removing RUC capacity from the ORDC would have provided generators an additional $6.6 million and $18.6 million in revenue in 2016 and 2017, respectively. Given that total generator revenues in ERCOT were about $8.4 billion in 2016 and $9.5 billion in 2017, the adders respectively represented about 0.07% and 0.2% of total revenue, staff said.

The ISO study estimated it would cost $15,000 to $25,000 to modify ERCOT's systems to remove online RUC and RMR resources from the ORDC capacity value, and could be done internally within 60 days.

ERCOT will include the revised protocol language for its April 10 Board of Directors meeting.

PUC to Intervene at FERC in MISO's Docket

Following the PUC's executive session, Walker announced the commission would be intervening in MISO's application before FERC to create targeted market efficiency projects, a new category of small interregional transmission projects (ER18-867).

Walker also said Thomas Gleeson, the commission's director of finance and administration, will serve as its interim executive director until a full-time replacement can be found. Brian Lloyd resigned from the position March 1, after seven years. (See *Texas PUC Executive Director to Resign*.)

— Tom Kleckner

RTO Resilience Filings Seek Time, More Gas Coordination

Continued from page 14

ERCOT, Texas PUC: Consider All Foreseeable Threats

ERCOT and the Public Utility Commission of Texas filed joint comments in the docket, although they noted that the Texas grid operator does not fall within the Federal Power Act's definition of an RTO or ISO and "therefore does not fall within the coverage of the commission's order."

Still, both entities saw "great value in providing input" because it could inform FERC's "possible application of its authority over public utility tariffs" and affect the potential development of NERC reliability standards, to which ERCOT is subject.

The two entities agreed with FERC's concept of resilience. "Any disturbance to the bulk power system that impairs the continuous provision of electric service has, to that same extent, impaired reliability," they said. "ERCOT and the PUC view resilience as an important subset of their existing reliability responsibilities."

They urged FERC to look beyond "high-impact, low-frequency events" such as cyberattacks, fuel-supply disruptions and extreme weather events. "The ultimate goal of policymakers should be to ensure that *all* foreseeable threats to the reliability of the bulk power system are identified and addressed in the most cost-effective way," they wrote.

ERCOT and the PUC also underscored the importance of Texas' energy-only market design in ensuring system resilience, saying it "is inextricably linked to long-term system reliability." As an example, they referred to February 2011, when cold temperatures knocked several generators offline and market prices hit the cap ($3,000/MWh, which has since been raised to $9,000/MWh).

"This resulted in severe financial consequences to generators with day-ahead commitments that failed to generate in real time, just as it greatly rewarded those generators that stayed online during the event," ERCOT and the PUC said. Subsequent improvements in plant weatherization resulted in "substantially fewer generators suffering equipment failures" during similar events in 2017 and 2018.

"In short, ERCOT's scarcity pricing mechanisms are designed to alleviate the need for many resilience-based regulatory controls," they wrote in the 22-page filing.

ERCOT and the PUC said they address resilience concerns in operating and planning the grid, noting the "greater penetration of renewable resources … compared with most other ISOs" and the "greater vulnerability" they pose to certain extreme weather events.

"ERCOT has robust processes in place to ensure the ERCOT system will be operated in a way that can resist and recover from a variety of foreseeable disturbances," they wrote. "These processes will continue to identify other areas for improvement as the system evolves."

— Tom Kleckner

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ISO-NE NEWS

FERC OKs Lower Delist Threshold in ISO-NE

By Rich Heidorn Jr.

FERC on Friday approved ISO-NE's reduction in the dynamic delist threshold for Forward Capacity Auction 13, turning aside protests by generators.

The commission reduced the threshold to $4.30/kW-month from the $5.50/kW-month the RTO had used in FCAs 10-12 (ER18-620). The threshold, which must be revised every three years, is a key parameter for generators considering retirement, which must submit delist bids to opt out of the capacity auction.

ISO-NE's auction use static and dynamic delist bids. A static bid must be filed before the auction for review by the Internal Market Monitor; bids below the dynamic delist bid threshold will be removed from the capacity market for one year.

Dynamic delist bids are submitted during the auction and are not subject to IMM review. If the auction price falls below a resource's delist bid, that resource is removed from the auction and does not acquire a capacity supply obligation.

ISO-NE's proposed threshold is calculated by the IMM, whose objective is to set the level slightly below the competitive price from the marginal resource in the FCA to increase the likelihood that the marginal bid is subject to a market power review. If the threshold is too high, the RTO says, existing suppliers — who know the remaining supply in each FCA round — can exert market power by increasing the FCA clearing price through their dynamic delist bids.

FCA 13 will be the second consecutive reduction in the threshold. In FCA 9, the threshold was raised from $1/kW-month to $3.94/kW-month.

ISO-NE accepted the retirement bid from PSEG's 383-MW Bridgeport Harbor 3 coal-fired unit for Forward Capacity Auction 12. | *PSEG*

Methodology

The IMM calculated the $4.30 threshold based on the most recent supply-and-demand curve information and data on shortage conditions and resource performance. The Monitor said it was unable to use recent static delist bid data to represent net going-forward costs because suppliers have submitted fewer static bids in recent auctions. Instead, the IMM estimated going-forward costs using a proxy price calculated from a weighted average of capacity that remained in the auction during the last round of FCA 11. It also used several "implied bids" — bids from resources that did not submit a dynamic bid in the final round of the auction, instead remaining to the end-of-round price of $4/kW-month.

ISO-NE said the decrease in the threshold is consistent with changes in supply and demand, noting that the amount of capacity in the RTO has increased each year since FCA 9, while the installed capacity requirement has consistently decreased. The RTO estimated a surplus of 1,250 MW for FCA 12.

Protests

The New England Power Generators Association (NEPGA) protested the RTO's threshold, saying the IMM's methodology was inconsistent with that used in updates since FCA 9 and that it will distort market signals and harm reliability. It noted that the Monitor disregarded cost-based offers from fossil steam resources that had been used in the past, instead using a forecast of future market conditions.

The generators group also challenged ISO-NE's assumption that the capacity market faces a surplus in future auctions, and that the number of hours of capacity scarcity conditions will decrease.

By sending a market signal that offers above $4.30/kW-month are unlikely to clear, NEPGA said, generators will be inclined to make below-cost offers to obtain capacity revenues.

Public Service Enterprise Group also protested, saying the $5.50/kW-month threshold is already less than 70% of the net cost of new entry (CONE) for FCA 12 and that offers in that range should be considered competitive. The first seven auctions used a threshold that was 80% of net CONE, PSEG said.

Ruling

FERC sided with the IMM's methodology, saying it was reasonable given the changing supply-and-demand dynamics since the last update. "We agree with ISO-NE and [the New England Power Pool] that the question before the commission in this proceeding is whether ISO-NE has demonstrated that its proposed dynamic delist bid threshold and the methodology that the IMM used to calculate it are just and reasonable, not whether ISO-NE's proposal is more or less just and reasonable than protesters' proposed alternatives," FERC said.

It added, "The fact that the IMM used

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ISO-NE NEWS

Split FERC Approves ISO-NE CASPR Plan

Continued from page 1

because of the MOPR. The RTO will phase out the renewable technology resource (RTR) exemption, which has allowed it to clear 200 MW of renewable generation in its capacity auction annually (to a maximum of 600 MW) without regard for the MOPR.

CASPR failed to win a 60% supermajority among stakeholders, and the RTO's filing was opposed by its External Market Monitor, Massachusetts Attorney General Maura Healey, municipal utilities, Connecticut, the Natural Gas Supply Association, a coalition of environmental groups, the New England Power Generators Association and several merchant generators. (See *ISO-NE Defends CASPR Against Protests*.)

The opponents challenged the definition of sponsored-policy resources (SPRs) eligible for the SA; the cut-off date of Jan. 1, 2018; restrictions on interzonal transfers; and the phase-out of the RTR exemption without a "backstop" to ensure SPRs receive capacity obligations. They also expressed fears that "fictitious" resources would enter the auction to collect revenues from SPRs and that the construct would worsen the region's fuel security concerns.

The commission rejected all the protestors' concerns, approving CASPR as proposed. The commission did acknowledge concern over potential anticompetitive bidding, urging ISO-NE "to work with its stakeholders to pursue market enhancements" to strengthen market mitigation rules.

Powelson Dissent

Powelson, however, wrote a dissent calling the construct "a complicated, patchwork solution that will neither accommodate the desires of the states, nor send proper price signals to market participants."

"The two goals that CASPR tries to achieve are fundamentally in conflict and cannot coexist in one market," he wrote. "By trying to both accommodate state policies and protect the [Forward Capacity Market], CASPR will likely only accomplish one goal at the expense of the other. Today's decision threatens the viability of the FCM to serve as a mechanism to ensure resource adequacy in ISO-NE, and therefore, it is unjust and unreasonable and should be rejected."

Powelson said he shared the states' concern that their ratepayers do not "pay twice" for capacity, as would happen if state-sponsored resources failed to win capacity commitments. "However, the states had the opportunity to foresee this 'double-payment' problem when they made the decision to support resources outside the market. … So unless the states are willing to reassume complete responsibility for resource adequacy, they must accept that the commission is required to take action to ensure the viability of the capacity markets."

Powelson said CASPR will not prevent state-sponsored resources from suppressing prices, because they are exempted from the MOPR after their first year and thus permitted to offer into the market at a lower price that reflects their out-of-market revenues. "Instead of incentivizing developers to compete for market revenues, the message the commission is sending to market participants is that the best way to ensure the future viability of a particular resource is to seek state support," he said.

In addition to suppressing prices, Powelson said CASPR also may fail to accommodate state-supported resources. "The FCM has been clearing at lower prices over the past few years, making it unlikely — if this trend continues — that a resource near retirement (i.e., one with high going-forward costs) would clear in the primary auction. As a result, there may be few or no resources eligible to swap capacity supply obligations with eligible state-supported resources."

Glick: MOPR Rationale 'Ill-Conceived'

Glick took the opposing view in supporting CASPR, but he dissented over the order's "suggestion" that state-sponsored resources must either be subject to MOPR or some alternative mechanism for ensuring state policies don't interfere with the capacity market. "That rationale — which is not adopted by a majority of the commissioners that support the order — is ill-conceived, misguided and a serious threat to consumers, the environment and, in fact, the long-term viability of the commission's capacity market construct," Glick said.

Instead, Glick wrote, the commission should "stop using the MOPR to interfere with state public policies and, instead, apply the

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FERC OKs Lower Delist Threshold in ISO-NE

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different data than it has used in the past to calculate the dynamic delist bid threshold does not, on its own, render ISO-NE's filing unjust and unreasonable.

"While NEPGA argues that the dynamic delist bid threshold should be based on the costs of oil-fired resources because they are typically the marginal resource, we find compelling ISO-NE's statement that, under current market rules and conditions, it is difficult to forecast with certainty the type of resource that will submit the marginal bid," the commission continued. "As ISO-NE notes, several different resource types have submitted dynamic delist bids near the auction clearing price in the last two auctions."

It rejected NEPGA's prediction that bids above the reduced threshold will not clear as "speculative."

"We agree with ISO-NE that suppliers should not rely on the dynamic delist bid threshold as an indicator of the likely clearing price in the next auction; the purpose of the dynamic delist bid threshold is not to signal the likely market clearing price but instead to help ensure that the marginal bid is subject to IMM review for the potential exercise of market power. Further, the proposed dynamic delist bid threshold does not prevent capacity suppliers from submitting properly supported delist bids that exceed the threshold."

The commission said PSEG's protest that the reduced threshold will exacerbate problems with the delist process was beyond the scope of the proceeding.

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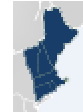

Split FERC Approves ISO-NE CASPR Plan

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MOPR in only the limited circumstance for which it was originally intended: to prevent the exercise of buyer-side market power."

Glick contends FERC has misinterpreted the Federal Power Act, failing to respect "that states, not the commission, are the entities primarily responsible for shaping the generation mix."

"The fact that state policies are affecting matters within the commission's jurisdiction is not necessarily a problem for the commission to 'solve' but rather the natural consequence of congressional intent.

"I do not believe that it is — or should be — the commission's mission to create an electricity market free from governmental programs aimed at legitimate policy considerations, such as clean air and combatting climate change," he continued. "Nevertheless, today's order appears to suggest that it is appropriate for the commission to insert itself into the states' domain."

Glick said the commission's goal of ensuring "investor confidence" in the capacity market will result in over-procurement; with significant excess capacity, ISO-NE's auction should send price signals inducing high-cost resources to retire. "There is nothing in the record that supports the conclusion that, to ensure resource adequacy in New England, the commission must act to ensure that investors in all forms of generation — both existing and new — remain confident that they will recover their costs," he said.

Glick also said his support for CASPR is predicated on whether it facilitates the entry of state-supported resources into the FCM.

"To the extent that, as implemented, the CASPR proposal does not facilitate the entry of state-sponsored resources, it may render ISO-NE's tariff unjust and unreasonable," he concluded.

LaFleur: MOPR 'A Blunt Instrument'

LaFleur also supported CASPR but issued a concurring statement joining Glick in disagreeing with paragraph 22 of the order, which she said suggested MOPR should be the "standard solution" against the impacts of all state policies.

LaFleur said MOPR is "a blunt instrument" and that other constructs, such as carbon pricing, can also achieve state objectives within the market.

"I acknowledge that these issues are not easy, as evidenced by the split commission decision today. I also believe that these issues do not lend themselves to a cookie-cutter solution to be broadly applied across all regions," she wrote. "I therefore hope we receive market design proposals developed by other RTO/ISOs and their stakeholders. Without prejudging any specific proposal, I believe we should be open to region-specific solutions of different types."

ISO-NE News

Low ISO-NE Prices Persisted in 2017

By Amanda Durish Cook

ISO-NE power prices last year climbed from record lows, but they didn't recover by much.

The RTO said last week that cheap natural gas and declining regional demand left 2017 average wholesale prices at the second-lowest level on record.

In 2016, prices dropped to their lowest levels since New England's current competitive electricity markets were established in 2003, according to ISO-NE.

Prices averaged $33.94/MWh in 2017, up 17.3% from the previous year but nearly 35% under 2004 levels. Last year's wholesale market value of $4.5 billion was also the second-lowest on record, compared with 2016's record low of $4.1 billion.

ISO-NE attributed the soft market to the second-lowest natural gas prices since 2003 ($3.72/MMBtu) and mild weather throughout much of the year. Gas prices averaged $3.09/MMBtu in 2016.

Gas-fired generation last year accounted for 48% of the power produced within New England and 41% of the region's total energy mix, including imports.

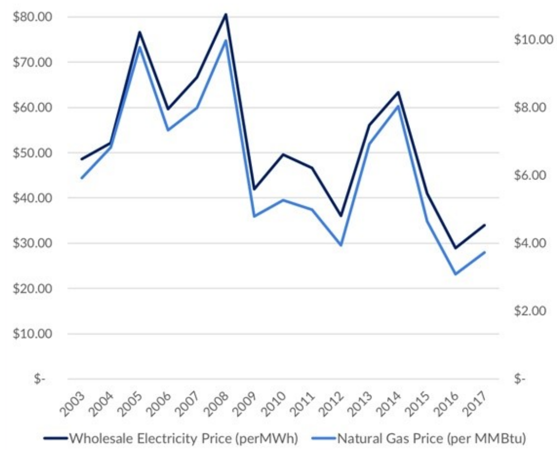
The RTO said the extreme cold that arrived the last week of December constrained gas supplies and drove up prices, yielding $396 million of the month's total electricity sales of $856 million.

But aside from December, consumer electricity demand remained light, averaging 121 GWh in 2017, down 2.7% for the year, according to preliminary numbers, ISO-NE said.

"Wholesale power prices were low in 2017 because of low fuel costs and relatively low consumer demand for power during most of the year," ISO-NE CEO Gordon van Welie said in a release. "However, the last week of December illustrates the impact of constrained natural gas supplies on electricity prices. The challenging operating conditions also highlighted a growing need for competitive markets to more transparently signal the potential costs of inadequate fuel security, which creates the potential for significant reliability risks to the region."

August and June of last year saw the seventh and eighth lowest monthly price averages on record, at $23.77/MWh and $23.93/MWh, respectively. ISO-NE's nine lowest-priced months all occurred in 2015, 2016 and 2017. The RTO's highest prices occurred in January 2014 during that winter's "polar vortex," when prices averaged $162.88/MWh.

The RTO also said consistently improving transmission congestion played in role in keeping 2017 prices low. ISO-NE said that about $10 billion in transmission upgrades since 2002 has dropped congestion and reliability-related costs from more than $700 million in 2006 to about $57 million in 2017.



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ISO-NE NEWS

RTO Resilience Filings Seek Time, More Gas Coordination

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An ISO-NE study found that extended outages of key energy facilities would result in as much as 138 hours of load shedding by 2024. | *ISO-NE*

ISO-NE Sees Growing Fuel Security Risks

ISO-NE filed a 61-page response citing winter fuel security as its most significant resilience challenge and asking FERC to allow it until the second quarter of 2019 to develop a long-term solution through its stakeholder process.

The RTO said the stakeholder discussions will build on the sobering findings of its Operational Fuel Security Analysis (OFSA) report issued in January, which found the region would face energy shortfalls because of inadequate natural gas supplies in almost every fuel-mix scenario by winter 2024/2025, "requiring frequent use of emergency actions to fully meet demand or protect the grid." (See *Report: Fuel Security Key Risk for New England Grid*.)

ISO-NE said potential solutions range from "changes to Pay-for-Performance parameters to market designs that increase incentives for forward fuel supply and resupply to inclusion of opportunity costs associated with scarce fuels and emission allowances."

"New England's fuel-security challenges do not lend themselves to easy solutions. Thus, the proposed time frame is necessary to allow for a systematic and deliberative regional process for examining the risks and possible solutions — a complex undertaking," the RTO said. "A key question to be addressed in these discussions will be what level of fuel-security risk ISO-NE, the region, policymakers and regulators are willing to tolerate."

The RTO noted that New England lacks indigenous fossil fuels production, leaving it reliant on imported fuels, including from five interstate natural gas lines whose winter capacity is mostly consumed by local distribution companies for heating. Generators are dependent on capacity released by utilities in the secondary market.

ISO-NE said it has made changes to its market design, operating procedures and systems since identifying fuel security as a problem during a cold spell in 2004. The RTO noted corrective actions it has taken, citing a change in the timing of the day-ahead market to give generators more time to procure gas; allowing market participants to modify their offers on an hourly basis to reflect changing fuel costs; Pay-for-Performance rules, which will take effect June 1; and the winter reliability program that Pay-for-Performance will replace.

But the problem has worsened as generators with onsite fuel have retired, largely replaced by natural gas-fired generators relying on just-in-time deliveries.

Changing Fuel Mix

In 2000, oil- and coal-fired power plants produced 40% of the electricity generated in New England, while natural gas fueled just 15%. Since then, the region added 16,000 MW of gas-fired generation while losing 4,600 MW of non-gas generating capacity.

By 2016, gas-fired generation was responsible for 49% of the RTO's power, with coal and oil reduced to 3% of production, although they remain almost 30% of the region's capacity. Natural gas' generation share is expected to grow to 56% in 2026 while another 5,000 MW of coal- and oil-fired generation is at risk for retirement.

During the December 2017-January 2018 cold spell, oil and coal plants, which had been producing only 2% of the region's electricity, were called on to supply one-third of New England's power. Natural gas-fired generation dropped from almost half to less than one-quarter.

"With oil-fired generation operating at or near capacity, oil supplies, as well as emission allowances, at power plants around the region began to deplete rapidly over the two-week period, making system operations extremely challenging and significantly increasing the reliability risk to the system," ISO-NE said.

The region, which has relied on dual-fuel capability in previous winters, said that option is becoming less viable "as emissions restrictions are tightening dual-fuel generators' ability to use the oil-firing capability."

The OFSA report was the first time ISO-NE had performed a deterministic analysis that looked at the entire three-month winter season between December and February as opposed to a single forecast winter peak day.

The study found that load shedding would be needed to maintain system balance in 19 of the 23 scenarios considered and that extended outages of any key energy facilities — the Distrigas and Canaport LNG terminals; the Millstone nuclear plant; or an interstate pipeline compressor station — would result in as much as 138 hours of load shedding.

The analysis said load shedding could be minimized with higher levels of LNG, imports and renewables, changes that would require new transmission and "advanced arrangements for LNG with assurances for winter delivery."

While most of its response focused on fuel security, ISO-NE also cited as risks cybersecurity, physical security and geomagnetic disturbances, issues it said were being addressed "in other forums."

— Rich Heidorn Jr.

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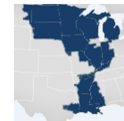

Monitor Backs MISO Uninstructed Deviation Proposal

By Amanda Durish Cook

CARMEL, Ind. — MISO's Independent Market Monitor is backing the RTO's proposal to revise its uninstructed deviation rules to allow generators to recoup a portion of make-whole payments even when their ramp rates fall short of expectations.

Monitor David Patton said last week that he now favors the "less draconian" performance-based proposal over his original recommendation from last year's State of the Market report.

MISO's plan would calculate a generator's uninstructed deviation by comparing the time-weighted average of its real-time ramp rate with its day-ahead offered ramp rate, while allowing for a 12% tolerance from set point instructions. The proposal eliminates the RTO's current "all or nothing" eligibility for make-whole payments, instead allowing generators to collect full payments when they respond to dispatch instructions at a rate of 80% or higher over an hour, while excluding payouts when performance rates fall below 20%. Units operating between those two thresholds would earn make-whole payments in proportion to performance.

The RTO currently flags generators that deviate from ramp rate dispatch instructions by more than 8% over four consecutive five-minute intervals, putting them at risk of losing day-ahead margin assurance payments (DAMAPs). The new approach would eliminate all current ramp rate requirements except for the one requiring rates of greater than 0.5 MW/minute.

The MISO Market Subcommittee meets on March 8. | © RTO Insider

Patton said MISO's time-weighted approach provides generators greater incentive to follow their offered ramp rates than his earlier proposal requiring units to move at least half their offered ramp rate within a 20-minute grace period before being flagged and losing make-whole payments. (See *MISO Tempers Dispatch Plan After Stakeholder Pushback*.)

"That 15 minutes is a knife edge," Patton said of the originally proposed 20-minute grace period before becoming ineligible for DAMAPs. "Generators motionless after 15 minutes will have to move at 100% of their ramp rate immediately to avoid exceeding 20 minutes."

He also pointed to the benefits of performance-based partial payments.

"Over the course of an hour, generators will have a stronger incentive to perform better. If you perform reasonably well, you'll make more money than if you don't perform reasonably well," he said.

Patton said MISO generators have so far been discouraged from providing a "multipoint" ramp rate that factors the time it takes to move a unit in the first few moments after firing it up. He said using an average of hourly performance will allow for nuances.

Some stakeholders agreed that it was a good idea to allow a lagging lead-time for slow-moving units but said the proposal doesn't help wind and solar generators, which have a tendency to be flagged for excessive energy production.

Patton acknowledged that wind power may need a "special rule," saying MISO could make "simple" changes to excessive energy flags for wind only when the excessive ramping doesn't cause congestion.

MISO plans to continue refining the uninstructed deviation proposal through April.

MISO Closing in on External Capacity Zones

By Amanda Durish Cook

CARMEL, Ind. — After almost three years of deliberation, MISO is putting the final touches on a plan to create external resource zones for its annual capacity auction by 2019.

Under the proposal, which is poised for a FERC filing at the end of this month, MISO would alter its Planning Resource Auction to include external resource zones based on neighboring balancing authority areas (BAAs). In cases of price separation, the RTO would also distribute historical supply arrangement credits from excess auction revenues as a refund to external resources with long-term and consistently used historical supply agreements.

The proposal would also establish new zonal capacity export limits in time for the 2019/20 planning year auction. Those limits would be based on the unforced capacity values for external resources participating in the auction in each external zone.

External zones would not have capacity import limits, planning reserve margin requirements or local clearing requirements. Resources in zones based on BAAs that border MISO Midwest zones will clear at one price based on a subregional unconstrained auction clearing price, while those in BAAs bordering MISO South will receive another price. BAAs that border both MISO Midwest and MISO South — Tennessee Valley Authority, SPP, Associated Electric Cooperative Inc. and Southwestern Power Administration — will receive a blended price. (See *MISO Postpones External Zones Until 2019 Auction*.)

Speaking at a March 7 Resource Adequacy Subcommittee, Laura Rauch, MISO's director of resource adequacy coordination, said the RTO would provide capacity hedges only to external resources with historical capacity arrangements, despite stakeholder requests for hedges for other newer external resources.

MISO intends to tweak the proposal before filing, including adding potential penalties for external resources that don't offer into the PRA after qualifying and registering for the auction. Under the current proposal,

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MISO News

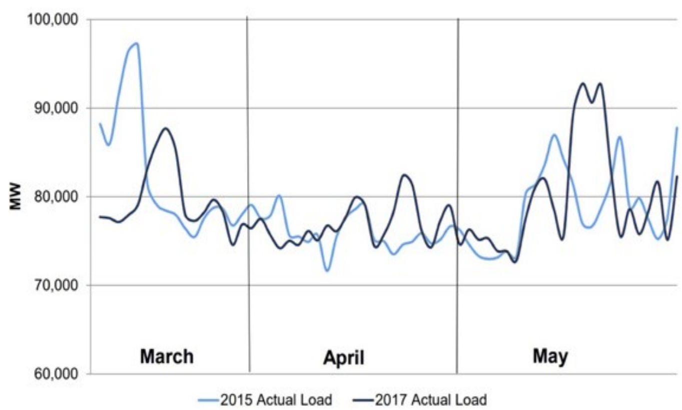
Outages Small Risk for MISO Spring Operations

By Amanda Durish Cook

CARMEL, Ind. — In what marked a first for the grid operator, MISO last week detailed its spring readiness and said there's a small possibility of emergency conditions.

While the RTO expects to have adequate resources on hand to meet sometimes volatile demand, it might also have to rely on emergency operating procedures during what was once considered a calm shoulder period, stakeholders learned during a March 8 Market Subcommittee meeting.

"Projected spring transmission and generation outages show challenging but manageable outages, similar to recent years," said Jeanna Furnish, MISO manager of resource planning and transmission studies.



| MISO

MISO's analysis shows a 25% probability it will need to invoke systemwide emergency operating procedures during the spring, but only if either loads or forced outages are higher than normal, Furnish said.

"My presence here isn't to cause any alarm but to talk about … the realities of challenges that may exist on the system," Furnish said.

Based on forecasts from the National Oceanic and Atmospheric Administration, the RTO is expecting a warmer-than-usual spring for MISO South and normal to above-normal precipitation in most of its footprint.

MISO said volatile spring loads that deviate from forecasts will require careful coordination of outages.

Furnish pointed out that MISO maintains a nonpublic member webpage called "Maintenance Margin" that keeps a monthly forward account of how many megawatts can be taken out of service without affecting reliability. The RTO uses the data to inform generators when it predicts outages will have an impact on reliability and will recommend alternative outage schedules.

Last year, high generation and transmission outages paired with unseasonably elevated loads in MISO South produced an early April maximum generation event, unusual for a shoulder season, prompting the RTO to call on load-modifying resources for the first time in a decade. The event prompted the Independent Market Monitor to call for MISO to have increased authority over approving maintenance outages. (See *4 LMRs Face Penalties after MISO Max Gen Emergency*.)

Customized Energy Solutions' Ted Kuhn asked if Maintenance Margin provided any indication that emergency conditions were imminent last spring.

"Was the Maintenance Margin showing a deficit, or did we just fall into a black hole?" Kuhn asked.

Furnish didn't know but said MISO continues to work with stakeholders to enhance outage coordination, including developing reserves that can be available within 30 minutes and improving congestion management with PJM at the seams by swapping control of flowgates.

MISO did not venture a guess about the projected spring peak. The RTO is planning for a 126-GW summer peak load, which it predicts will require a 17.1% planning reserve margin. (See *MISO Planning Reserve Margin Climbs to 17% for 2018/19*.)

MISO Closing in on External Capacity Zones

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those resources would only face "questions" from the Independent Market Monitor but face no specific consequences for withholding, Manager of Resource Adequacy John Harmon said.

Rauch also said stakeholders are still asking how MISO will differentiate a "border external resource" from other external resources. In November, MISO said it identified 3,837 MW of capacity from potential border external resources, which have direct electrical connections to the RTO but are located in another balancing authority.

Some stakeholders last month said that the concept of border resources amounts to preferential treatment of some external resources.

Rauch clarified that a border external resource's point of interconnection must be a substation on the border.

"We really want these to be resources physically on the border," she said.

MISO will rely on the volume of zonal capacity registered to participate in the auction to calculate an external zone's capacity export limits, which will be posted each November ahead of the auction, Rauch said. Participating resources must maintain firm transmission to at least the MISO border, she noted.

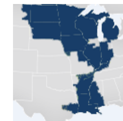
"Trying to study a slice of PJM or SPP" to determine a capacity export limit is too complex a task, Rauch said.

She said MISO does not foresee any binding external capacity export limits, except in rare cases that exports fail a simultaneous feasibility test.

If FERC approves the filing, MISO will begin developing business practice manual language with stakeholders beginning in June, Rauch said.

Meanwhile, MISO will open its 2018/19 PRA offer window at 12:01 a.m. on March 27 and close it on March 30 at 11:59 p.m. Results will be posted by April 12.

MISO NEWS



MISO RASC Zeroes in on Priorities

By Amanda Durish Cook

CARMEL, Ind. — MISO's Resource Adequacy Subcommittee will devote time this year to several projects focused on improving the RTO's resource adequacy construct, stakeholders learned last week.

Key among the efforts: a continuing discussion on how to deal with the shifting availability of resources.

John Harmon | © RTO Insider

Speaking at a March 7 RASC meeting, Manager of Resource Adequacy John Harmon said the seven projects are the result of a draft work plan MISO began in January. They were prioritized based on previous commitments to stakeholders in 2017, the urgency of each project, and the staff and capital spending available to devote to each project. (See *MISO Seeks To-Do List for Resource Adequacy Panel*.)

Harmon noted that the RASC will naturally dedicate time to discussing the nearly completed proposal to create external resource zones for the RTO's Planning Resource Auctions. (See related story, *MISO Closing in on External Capacity Zones*, p.24.)

Resource Availability and Need

The RASC's 2018 priorities will also include a larger discussion on resource availability and need, a topic evolving from MISO's former proposal to create seasonal capacity procurement requirements, a generally unpopular move among stakeholders.

MISO will now consult with stakeholders to determine whether it should revise current resource availability requirements and price signals in the face of shifting availability, itself a product of tightening supply, increased renewables, more frequent extreme weather events and an aging baseload fleet more susceptible to outages. RTO officials say the proposal is no longer as simple as applying separate clearing requirements to two-season and four-season capacity auctions.

The effort will also explore the possibility of MISO factoring the effect of outages during peak load into its loss-of-load expectation study in time for the 2019/20 planning year, which could boost the planning reserve margin requirement. MISO is planning to inform its modeling with an average of outages on peak during the last five planning years, translating to an average 729 MW in outages and a 0.6% increase in the reserve margin, Resource Adequacy Coordinator Ryan Westphal said. MISO's current modeling assumes generation owners do not schedule any planned outages during the peak. (See *MISO to Fold Outage Forecasting into Larger Resource Effort*.)

"Zero seems we're not modeling the reality — the risk — correctly," said MISO Director of Resource Adequacy Coordination Laura Rauch.

"Current modeling practice could be relying on resources that might not be available. … These ought to be captured," Westphal added.

Speaking on behalf of the Coalition of Midwest Transmission Customers, attorney Jim Dauphinais warned against "socializing the cost of planned outages" with an increased planning reserve margin if only a few units are the culprits of planning outages on peak.

"I disagree; we're a risk-sharing insurance pool," responded Consumers Energy's Jeff Beattie, adding that generation operators agreed in MISO's Tariff that even companies covering reliability with several smaller units would share risk with companies relying on a single large unit that carries more outage risk.

Westphal asked stakeholders to provide more feedback by March 21, noting that MISO would need to complete a proposal by June to allow it to model planned outages on peak in the 2019/20 planning year.

Other RASC priorities this year will include:

- Improving alignment between MISO's loss-of-load expectation study and its annual resource adequacy survey with the Organization of MISO States;
- Discussing how energy storage resources could earn capacity accreditation;
- Discussing how behind-the-meter generation can fit into MISO's resource adequacy construct;
- Deciding whether MISO should bar units on extended outages from offering into the capacity auction;
- Determining the best approach to potentially importing capacity from Ontario's Independent Electricity System Operator into MISO.

Harmon said MISO plans to postpone until next year a project that would alleviate partial unit clearing, which occurs when the RTO's algorithm clears a marginal offer on a *pro rata* basis, resulting in revenue shortfalls for resources that clear a fraction of their unforced capacity values.

The RASC will not focus on two other previous suggestions: developing forward capacity price indices and raising the PRA price cap above MISO's approximate $250/MW-day cost of new entry (CONE).

Harmon said MISO "has no role in bilateral markets" and "should not be involved in facilitating pricing information outside its markets." He also said there's no indication at this time that MISO's cost of new entry needs to be raised because auction clearing prices are far from closing in on the CONE.

MISO NEWS

No Refunds in 20-Year-Old Entergy Rate Complaint

By Amanda Durish Cook

Entergy will not have to issue refunds in a decades-long rate dispute with the Louisiana Public Service Commission, the D.C. Circuit Court of Appeals ruled last week.

In denying the PSC's petition for review, the court upheld FERC's decision not to order the refunds, acknowledging that the federal commission does not have a "generally applicable policy of granting refunds," something the court did not understand when it originally remanded the rate case (16-1382).

The issue dates back to 1995, when the PSC and the New Orleans City Council filed a successful complaint with FERC, arguing that Entergy's formula for determining peak load responsibility in its multistate system agreement was unfair because it included interruptible load in addition to firm load.

In a 2004 order, FERC found that certain aspects of Entergy's rates were unreasonable. And while the commission required Entergy to remove all interruptible load from its cost allocation, it declined to order refunds, concluding that the utility did not over-collect despite relying on an inequitable cost allocation.

FERC does not historically order refunds when "the company collected the proper level of revenues, but it is later determined that those revenues should have been allocated differently," the court noted.

The court said that in 2016, it was initially convinced by the PSC's argument that FERC had failed to "'reasonably explain the departure' from its 'general policy' of ordering refunds when consumers have paid unjust and unreasonable rates" and remanded the case to FERC. Last year, the PSC was still arguing at FERC that refunds to Entergy Louisiana could be possible. (See *FERC Accepts Entergy Revision on 'Moot' Settlement*.)

But, on remand, FERC told the court that it "actually has no general policy of ordering refunds in cases of rate design."

FERC acknowledged that throughout the case it had referred to "a 'general policy' in favor of refunds" but said that the phrase was a mischaracterization and that it has no such policy.

The court accepted the explanation, saying FERC had clarified its "previously muddled position."

"Now that the commission has corrected its characterization of its own precedent, we find that the commission's denial of refunds accords with its usual practice in cost allocation cases such as this one. We also find that the commission adequately explained its conclusion that it would be inequitable to award refunds in this case. The commission did not abuse its discretion. … We find that the commission has made its historic practice clear and justified its application of that practice here," the court said.

MISO NEWS

RTO Resilience Filings Seek Time, More Gas Coordination

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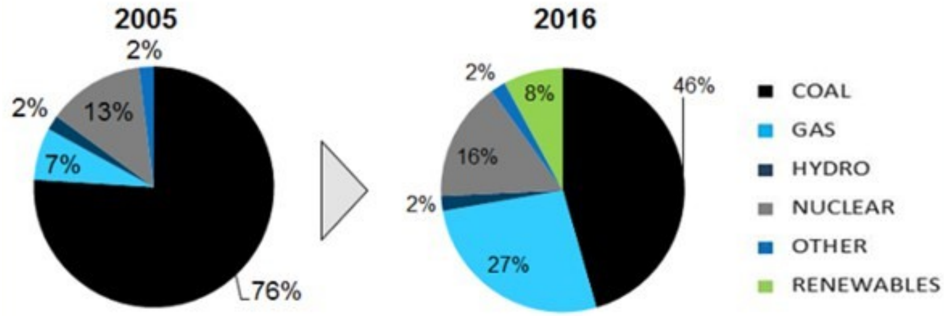

MISO's generation mix has changed dramatically since 2005. | *MISO*

MISO: Work Already in Progress

MISO's filing focused on the practices it already has in place to promote resilience and pointed out that its stakeholder processes and projects have been geared toward resilience "for nearly two decades." The RTO said it doesn't have any "imminent or immediate" resilience concerns.

"MISO's core foundation of ensuring regional reliability needs are met at the lowest possible cost has facilitated the creation of robust planning, operations, markets and security mechanisms that are utilized to not only identify, assess and avoid resilience threats, but also to mitigate any impacts that may occur from high-risk events," the RTO said.

Vice President of System Planning Jennifer Curran said MISO already works with stakeholders to ensure daily grid reliability and resilience.

"Grid resilience is core to our foundation and day-to-day activities at MISO," Curran said in a statement that the RTO issued in addition to the 52-page response to FERC. "We constantly evaluate our operations and look for opportunities to strengthen our systems, reduce risk and contribute to the dialogue and knowledge-sharing that benefits the industry and the power grid."

MISO said it addresses resilience through its biennial Market Roadmap, a process in which it and its stakeholders identify the most pressing market improvements to undertake. (See *MISO Accepting Market Roadmap Ideas*.) The RTO also said it enhances resilience through gas-electric coordination, drills on severe weather and other emergencies, and its annual Transmission Expansion Plan process. It currently studies "approximately 6,500 extreme events impacting loss of multiple facilities on the transmission grid" and maintains a cyber operations team to monitor critical systems.

In researching disruptive events, it said it found only one scenario that would violate the one-day-in-10-years planning criteria: "the extreme and long-term event of the loss of the largest natural gas pipeline for the entire summer peak season."

During January's extreme cold snap, MISO said it was armed with a better understanding of the limitations of the natural gas supply. (See *MISO Breaks down Recent Cold Snap*.) It also pointed out that it recently initiated research to study the impact that large gas pipeline contingencies have on its system. (See "Sign-of-the-Times Studies," *MISO in 2018: Storage, Software, Settlements and Studies*.)

It also said the replacement for its market platform computer system was selected following a "comprehensive assessment to determine the system performance and security requirements that will be necessary to meet MISO's long-term needs." (See *MISO Makes Case for $130M Market Platform Upgrade*.)

While MISO said it generally agreed with FERC's definition of resilience, it urged the commission to add a nod to the "changing nature of the electric grid."

For FERC to facilitate a resilient grid, MISO said the commission should make sure "inflexible" critical infrastructure protection compliance standards do not limit cybersecurity measures. It also urged the commission to research how to value resilience in the transmission planning process and "actively support" more efficient interregional operations that can respond to disruptions.

MISO called for "broader introduction of advanced operational tools" that can improve situational awareness and congestion management. "Current limitations in both processes and tools restrict the efficient use of transmission and redispatch opportunities to fully leverage available infrastructure. These limitations result in fewer operational options to address unplanned events that may test grid resilience," the RTO said.

As an example, it said, using the interregional transmission load relief (TLR) process to manage congestion may become inadequate as more intermittent resources join the grid. "RTO/ISO energy market advancements have facilitated the development of superior market-based congestion management tools, including redispatch, seams coordination and market-to-market processes that improve reliability and reduce costs (particularly when compared to TLR)," it said. It cited its coordination with PJM as "the model for seams operation" that could be applied "to advance interregional operations more broadly."

But MISO also said resilience planning shouldn't rest with RTOs and ISOs alone.

"The commission's evaluation of resilience issues should not be limited to just RTOs and ISOs; rather, grid resilience is a national issue that broadly impacts the bulk power system. Additionally, to the extent the commission is interested in addressing concerns at the distribution level, the commission should work in partnership with state regulators to help ensure a coordinated effort," MISO said.

— Amanda Durish Cook

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NYISO News

RTO Resilience Filings Seek Time, More Gas Coordination

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NYISO Cites 'Track Record,' Current Initiatives

NYISO's 26-page response noted that its most recent Reliability Needs Assessment concluded that the ISO will meet its transmission security and resource adequacy requirements through 2026.

It also identified six initiatives it is pursuing to respond to challenges resulting from "technological developments, economics, environmental considerations and public policies" transforming the grid: re-evaluating its ancillary services products and shortage pricing; ensuring that market price signals incentivize compliance with dispatch instructions; considering changes to the measurement of capacity to reflect resource performance during critical operating periods; evaluating deliverability and performance requirements for external capacity resources; potential enhancements to interregional transaction coordination; and better integration of energy storage and distributed energy resources.

It also said it will perform a "comprehensive re-evaluation" of its planning process to ensure it "stands ready to facilitate the transmission infrastructure additions and upgrades and other resources necessary to meet the evolving needs of the grid."

In addition, the ISO said its markets "inherently value and support elements of resilience," including the use of shortage pricing in the day-ahead and real-time markets. Since the 2013-2014 winter, the ISO said it has boosted the statewide 30-minute reserve requirement by 655 MW to 2,620 MW and implemented a new reserve region for Southeastern New York with a 1,300-MW operating reserve requirement.

It also cited its fuel inventories, gas-electric coordination and improved situational awareness from phasor measurement units added to the grid in recent years.

NYISO also pointed to the importance of its interconnections with neighboring regions, saying its exports helped ISO-NE survive fuel supply challenges during the cold weeks surrounding New Year's Day and "provided significant levels of emergency energy" to PJM for five hours on Jan. 7.

The ISO said its public policy planning process could result in changes to require additional resilience beyond that necessary to achieve minimum reliability requirements or additional infrastructure to improve energy delivery capability. Thus far, the process has identified two transmission needs: the 345-kV transmission project in western New York, expected in service in 2022; and AC transmission additions to relieve congestion on the UPNY-SENY and Central East interfaces.

The ISO said that because there are differences of opinions regarding the definition of resilience, "the commission could potentially facilitate this dialogue through a technical conference to explore near-term concepts being considered across the diverse regions of the country."

It also asked FERC to trust its stakeholder process, saying it "has a proven track record of success in addressing the challenges and opportunities facing the bulk power system and wholesale energy markets in New York."

"In recognition of this success, the NYISO respectfully requests that the commission allow the NYISO to continue to work with its stakeholders in assessing and developing the enhancements necessary."

— Rich Heidorn Jr.

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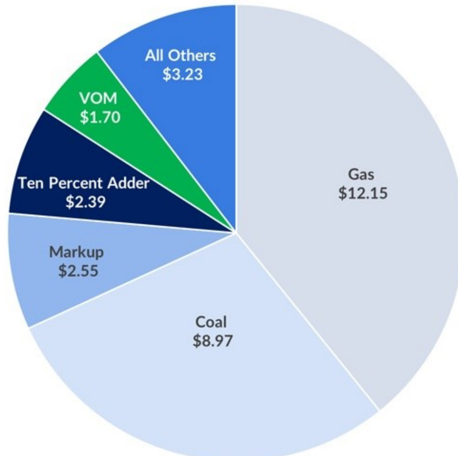
PJM NEWS

State of the Market Report Says PJM Prices Sufficient

By Rory D. Sweeney

While structural issues persist, PJM's markets were competitive in 2017, the RTO's Independent Market Monitor said Thursday, contradicting concerns from PJM and some stakeholders that prices are unsustainably low.

In his annual State of the Market Report, Monitor Joe Bowring noted that PJM's energy, capacity, regulation, synchronized reserve, day-ahead reserve and financial transmission rights markets all produced competitive results with competitive participant behavior, although all showed either market structure or design issues. Bowring recommended improvements for each market.



Components of real-time, load-weighted, average LMPs | *PJM*

But the results show that the generation fleet remains relatively diverse and that most plants are receiving enough revenue to be profitable. All diesel and pumped-storage resources, and nearly all gas-fired combustion turbines and hydro stations, received full recovery of their avoidable costs, as did 88% of oil- or gas-fired steam units and 86% of gas-fired combined cycle plants.

Among nuclear plants, 68% earned enough revenue to cover an industry-standard calculation of costs developed by the Nuclear Energy Institute.

Using capacity auction results going forward, the report found only four nuclear facilities are threatened with negative revenues: Oyster Creek (which is already slated for decommissioning), Davis-Besse, Three Mile Island (TMI) and Perry. Quad Cities and Byron, the beneficiaries of Illinois' controversial zero-emissions credits legislation, had been unprofitable four of the past five years but are projected to turn a profit through 2020.

The Salem nuclear plant also is expected to remain profitable through 2020. Asked why Exelon and Public Service Enterprise Group, which jointly own the two-unit facility in southern New Jersey, decided to halt capital expenditures at the plant, Bowring said he was "not quite sure" the reasoning.

"Based on publicly available data, it is more than covering its costs," he said. "Nuclear units are not making a lot of money, but generally … they are not receiving a retirement signal from the market."

"It's not surprising" that single-unit facilities are the ones that are getting that signal, Bowring said. Additionally, he argued that NEI's number was "inappropriate" because it included additional costs that were incurred in the aftermath of the Fukushima disaster in 2011. Using two-thirds of those costs, all but TMI and Davis-Besse will be profitable.

Just 52% of coal-fired plants recovered their avoidable costs, the report showed. PJM's plan to revise price formation would support large, inflexible units like coal plants, but Bowring said the reforms were not based on market flaws. Nearly 79% of the $24.7 million uplift costs from day-ahead operating reserve differences were paid to coal units in 2017, but not because of market design issues, he said.

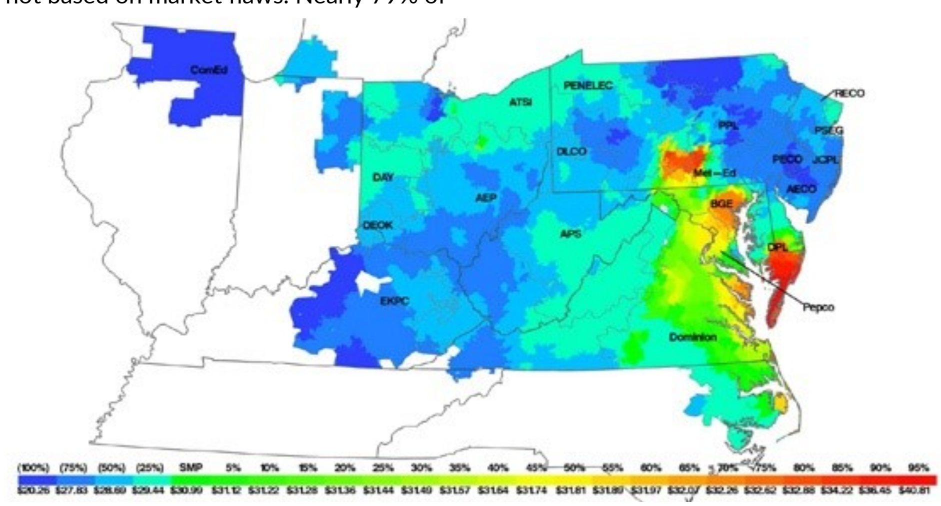
"That actually has to do with some very specific circumstances about coal units that have nothing to do with convexity and non-convexity and would not be affected by PJM's price-formation proposal," Bowring said.

Coal units also received nearly 85% of $20.4 million in uplift paid for reactive services, but gas turbines gobbled up the vast majority of the remaining $83 million uplift payments for lost opportunity cost, black-start services, local constraints control and balancing operating reserves.

While new combined cycle facilities could turn a profit in some zones, the revenue available in 2017 didn't cover the cost of entry for new combustion turbine generators, nuclear or other units.

"The PJM system is significantly long" on generation, Bowring said, in part because the RTO has been regularly over-forecasting demand. The average real-time demand was down 2.2% from 2016 to 86,618 MWh. Peak and average load were also down.

That factored into a $30.99 average LMP, which was up 6% from 2016 but lower than every other year since 2000. Much of that came from coal and gas prices, which combined to account for nearly 70% of the LMP.



Real-time, load-weighted, average LMPs | *PJM*

PJM NEWS

OC Briefs

Restoration Drill Date Set

VALLEY FORGE, Pa. — PJM will hold its spring restoration drill May 15-16, staff told attendees at last week's Operating Committee meeting. Invitations will be emailed March 19 to the contacts listed in transmission owners' restoration plans for the transmission operator, generation operator and training liaisons, PJM's Alpa Jani said.

Primary Frequency Response

PJM's Glen Boyle said stakeholders' work in the Primary Frequency Response Senior Task Force became more complicated and urgent after FERC issued Order 842, which requires all new generation that receives an interconnection agreement to provide primary frequency response. (See *FERC Finalizes Frequency Response Requirement*.)

The order silenced any debate about new facilities, so staff will instead focus on what should be required of existing units. The order could delay the PFRSTF's work, but the group plans to vote on proposals after its March 21 meeting. Stakeholder endorsement votes will likely be completed in June.

Unit-specific Parameter Adjustments

Jani also reviewed the statistics about the number of unit-specific parameter adjustment requests that PJM received this year. The request period closed on Feb. 28.

All final determinations will be made by April 15 so they can be implemented by the start of the delivery year on June 1. Jani noted that soak time information is only for reference this year but will be added as a parameter and integrated next year.

Resilience Update

Dean Manno | *© RTO Insider*

PJM's Dean Manno reviewed the RTO's resilience roadmap and highlighted the next steps for 2018. PJM is evaluating the needs for "extreme events," he said, including reserves and regulation requirements, transmission loading and triggers. Staff are also planning to review the weather/environmental and sabotage/terrorism emergencies sections of Manual 13 to see if anything should be added.

30-Minute Reserves

PJM's Vince Stefanowicz explained staff's thought process on developing a real-time 30-minute reserves product and announced that a problem statement and issue charge will be forthcoming in April.

Currently, 30-minute reserves are only procured in the day-ahead market, so when more primary reserves are needed, they're moved in from secondary reserves, which only serves to reduce secondary reserves rather than bringing in more units. The new product would achieve that, he said, "not just move things from secondary into primary."

| *© RTO Insider*

Dave Mabry with the PJM Industrial Customer Coalition said that "perhaps a bigger audience" would be necessary to make such changes and asked if the Market Implementation Committee would become involved.

"Conceptually, I'm in agreement with you," said PJM's Dave Souder, the interim chair of the Operating Committee. He said the plan is to figure out the operational needs, then determine what other committees need to be involved.

Implementing DER Ride Through

The RTO is hoping TOs will take the lead on implementing "ride through" for distributed energy resources, PJM's Andrew Levitt said. Ride through is the process of remaining connected to the grid during abnormal conditions. Despite being a "challenge" for large generators, Levitt said they're required to do it while DERs are not.

Today, DERs can trip off very quickly and potentially over a wide variety of variables. However, there are already 4,000 MW of distributed solar generation in PJM today with expectations of that tripling in the next three years, making it a significant issue if they all trip when the grid is having issues.

"We think ride through is critical for DER," Levitt said.

PJM recently published a draft revision of standards for DERs that would require ride through. However, it has no control over the net-metered solar that accounts for all the DER growth.

"We're looking to follow the utilities' lead on this topic ... but we also anticipate a public stakeholder process" to support stability bulk energy supply and move toward a single standard for implementation, Levitt said.

Changing Tier 1 Reserve Estimates

PJM's Joe Ciabattoni unveiled planned revisions to how Tier 1 reserves are estimated to address stakeholders concerns about major overestimates. (See "Investigating Improvements Based on Additional Cold Response Details," *PJM Operating Committee Briefs: Feb. 6, 2018*.)

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PJM NEWS

MIC Briefs

Exelon-backed Analyses Approved

VALLEY FORGE, Pa. — PJM stakeholders at last week's Market Implementation Committee meeting approved two problem statements and issue charges presented by Exelon, over objections from the Independent Market Monitor.

Exelon's Sharon Midgley presented both proposed investigations. The first problem statement and issue charge focused on PJM's rule for forfeiting revenue from financial transmission rights if a market participant's portfolio of day-ahead virtual bids creates a larger LMP spread in the day-ahead market than in real-time auctions.

Midgley argued that changes PJM implemented last year in response to FERC's order to revise the forfeiture rule have made the rule overly restrictive, which Exelon says resulted in forfeiture of substantially more revenue from legitimate positions. A year-over-year comparison of monthly forfeitures before and after the rule changes took effect in 2017 shows as much as a $1.8 million difference in a single month.

The Monitor's Howard Haas said that, while the rule changes have yet to be approved by FERC, they follow the commission's guidance on the required changes. Given all the changes in the rule, he said, it was expected that the forfeiture numbers would be different than under the old rule, and the results under the old and new rule are not directly comparable. He said the observed level of forfeitures to date are in large part a result of the retroactive application of the new rule. Since information has become available under the new rule, participants have changed their behavior and forfeitures numbers are down dramatically. (See *FERC Orders Portfolio Approach for PJM FTR Forfeiture Rule*.)

PJM attorney Jen Tribulski agreed with Haas that the revisions the RTO filed for approval are in line with FERC's order, but she said that Exelon's concerns are "probably worth a discussion here" and that the commission's order doesn't prevent stakeholders from discussing and seeking approval for additional revisions. PJM's Asanga Perera later noted in response to a stakeholder question that others have complained about the rule, though he didn't have an exact number.

"It's not only Exelon. We have seen other parties express concerns with the forfeiture rule," he said.

Some stakeholders were unconvinced by Exelon's argument but also reluctant to buck the tradition of supporting each other's requests to analyze market procedures.

"I don't know what we see that there is a problem, but I don't know that we have much objection," said Dave Mabry, who represents the PJM Industrial Customer Coalition.

Direct Energy's Marji Philips said she would support the request but that it "seems premature" given the amount of work already teed up in stakeholder committees and the lack of clarity on how many market participants have been negatively impacted.

On Midgley's second problem statement and issue charge on the exemption process for the must-offer rule, Monitor Joe Bowring said the focus of the analysis should expand to include how capacity interconnection rights (CIRs) would be handled for units that transition from capacity to energy. Midgley welcomed the revision.

Exelon's request comes in response to difficulties the company has experienced with the timing of the current exemption approval process, specifically that it may be physically impossible to install dual-fuel capability within the three months between the third Incremental Auction and the start of the corresponding delivery year. Sites without winter fuel supplies may need to construct onsite oil storage, which can't be completed in the three-month period. Midgley said it's unclear what documentation needs to be submitted to receive approval for an exemption on such grounds.

The proposal would have stakeholders consider revising the guidelines for documentation required by the Monitor and PJM to grant an exemption, implementing process reforms to improve efficiency and establishing a process for resources with an ex-

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OC Briefs

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The RTO is proposing to cap spin max at a unit's economic minimum and require that the spin ramp rate equal the economic ramp rate, he said.

"We find that during spin events this is an issue," he said.

A TO representative who asked not to be named voiced concerns about reducing too much spin and asked that additional data be presented to explain the problem. Ciabattoni agreed.

"I just want to make sure we're actually seeing a problem there as opposed to fixing a problem that doesn't exist because there's no way a resource could tell if there's going to be a Tier 2 payment," the TO representative said.

Tom Blair of the Independent Market Monitor said the issue is exacerbated because of how the reserve market is set up.

"There is no penalty for Tier 1 synchronized reserve not responding. There is, however, a significant incentive to overestimate your Tier 1 reserve," he said.

Blair explained that the reserve market is set up so that units can earn enough money that they still make a profit even with the penalties that occur if they don't respond when called upon.

"I think directionally this is worthwhile, probably helpful," said Carl Johnson, representing the PJM Public Power Coalition.

Calpine's David "Scarp" Scarpignato said another issue is that scarcity pricing is not being triggered when it needs to be and that "the issue is much broader than this."

RAS Removed

Commonwealth Edison is removing the Davis Creek remedial action scheme (RAS). The plan was needed to prevent thermal overloads in the event of losing a 345-kV line to the substation by auto-closing a 345-kV bus tie at the station.

A supplemental project to expand the 345-kV bus at the substation is expected to be completed by the end of the year.

— Rory D. Sweeney

PJM News

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isting must-offer requirement to become energy-only resources.

Both investigations were endorsed by stakeholders.

Hardware to Improve Day-ahead Performance

PJM announced it had purchased several new computer servers to address issues with delays in posting day-ahead auction results. The hardware was acquired as part of an ongoing two-year cycle to upgrade equipment, so there was no additional budget impact, PJM's Todd Keech explained.

"We're right into one of those refresh cycles now, so it was good timing," he said.

Chantal Hendrzak, who chairs the MIC, acknowledged requests to expand the bidding window but said the RTO is focusing on posting the results sooner rather than increasing flexibility.

Five-Minute Settlements to Begin

PJM's Ray Fernandez reminded stakeholders that units have until March 16 to sign up for five-minute settlements, which go into effect April 1. After that, resources will have to alert the RTO at least three days ahead of the desired change-over date before submitting five-minute revenue meter data.

Maintenance in Cost-Based Offers

PJM's Tom Hauske said the RTO is considering whether to include maintenance costs in cost-based offers. Special sessions on variable operations and maintenance (VOM) costs produced three proposals, among which stakeholders will be asked to choose at next month's meeting.

Cost-based offers created through current Manual 15 rules do not allow for inclusion of any maintenance costs. PJM's proposal would allow for maintenance attributed to running the unit and directly tied to electricity production by including FERC accounts minus labor costs. Generators could also add operating costs, such as lubricants, chemicals and other consumables, into incremental energy offers, but not VOM.

Energy-only resources or units that didn't clear the delivery year's Base Residual Auction could add their avoidable cost rate (ACR) fixed costs (such as staffing, taxes, fees, insurance and fuel availability) into their VOM, but capacity resources could not because they should recover those expenses through their capacity payments.

PJM also presented another proposal that would give resources the option of using its package or default resource-class VOM values calculated using U.S. Energy Information Administration data.

The Monitor's package would replace "incremental" with "short-run marginal" in the Operating Agreement and would operate under the premise that all maintenance and labor costs are included in a unit's capacity offer. The net cost of new entry (CONE) for each resource class would be modified to include maintenance and labor costs. Manual 15 would be stripped of all costs except short-run marginal ones: fuel, emissions, water, chemicals and consumables. A unit's ACR would encompass everything else, including project maintenance expenses.

"The IMM package is based on what a competitive offer in the market should be," the Monitor's Catherine Tyler said. "We also think this is the most straightforward and simple to implement."

Once a proposal is approved, stakeholders would discuss implementation and time frame, Hauske said.

PJM ICC's Mabry said "one of the big heartburns we have" is that overhaul and major inspection costs are included in VOM rather than ACR.

"That frankly weighs into the decision … should I go buy a new resource?" he said.

PJM's proposal operates under the theory that VOM is recovered after it's been spent, while ACR is what's projected to be spent, Hauske said. He pointed out that if gas prices go up and a unit decides to run — and therefore performs maintenance — less often, it would have already received recovery for the higher amount of maintenance if it was recovered through ACR.

A representative of a transmission owner who asked not to be named said the default values are "pretty conservative" and should be based on actual costs, not averages. Tyler said the Monitor publishes its own defaults, but the TO representative said they're not explained.

Long-term FTRs Undercut Annual FTRs

The Monitor appears to have won over PJM regarding its concerns about long-term FTRs. Haas presented analysis requested by stakeholders that showed the cost to auction revenue rights holders from the long-term FTRs market construct. Among other findings, Haas showed that over the past four planning periods, FTRs sold in the long-term market have been undervalued by more than $337.2 million compared to the annual FTRs for the corresponding delivery year. (See *PJM Stakeholders Decline to Change Market Path Rules*.)

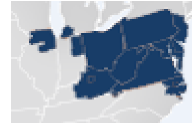
The current long-term market construct doesn't allow ARR holders to directly benefit from the sale of congestion rights, despite owning the rights to congestion, Haas said.

"I think we're on the same page with [the Monitor] about most of the issues," PJM's Brian Chmielewski said.

— Rory D. Sweeney

Planning Period	Long Term FTR Product				Annual (including self scheduled)	Long Term Percent of Total Net Revenue
	Year 3	Year 2	Year 1	Total Long Term		
2014-2015	$13,016,512	$7,176,209	$6,863,135	$27,055,856	$735,998,448	3.5%
2015-2016	$12,479,874	$7,378,550	$5,156,206	$25,014,630	$893,043,415	2.7%
2016-2017	$7,624,149	$2,105,984	$11,087,250	$20,817,382	$861,031,182	2.4%
2017-2018	$1,670,521	$7,210,445	$9,763,312	$18,644,279	$513,587,222	3.5%

Long-term FTR net revenue | *PJM*



AMP Seeks More PJM Scrutiny of TO Projects

By Rich Heidorn Jr.

American Municipal Power contended Thursday that PJM's limited review of transmission owner projects is not rigorous enough to ensure the RTO is avoiding unnecessary costs or that TOs' evaluation of other stakeholders' proposed solutions are accurate and unbiased.

AMP's Ryan Dolan noted that Manual 14B prohibits PJM from evaluating supplemental projects as part of the Regional Transmission Expansion Plan, meaning the plan can't capture whether a supplemental project creates or alleviates economic issues. "We can't assure an optimized build-out of the system," said Dolan, who presented a list of proposed rule changes at Thursday's Planning Committee meeting.

Dolan said PJM's limited review was not a problem in the past but that the RTO should provide more scrutiny now, because supplemental and other TO projects represented 88% of RTEP spending last year.

"There's information that PJM has that the TOs don't have, that we [stakeholders] don't have," said Dolan, who said the RTO should tap all available expertise in its analyses.

'Do No Harm' Reviews

Dolan spoke after Aaron Berner, PJM manager of transmission planning, explained the RTO's "do no harm" reviews of baseline upgrades, supplemental upgrades and new service requests. The review is intended to identify any reliability issues caused by new upgrades, determine if the upgrades should be more or less "robust" and assess the cost efficiency of packages of upgrades needed to correct reliability violations.

The testing required depends on the scope of the upgrade, not the type of upgrade, Berner said. No analysis is required for direct in-kind replacements, while minor changes to impedances or ratings undergo "minimal analysis." Significant changes to impedances, ratings or new topology may require "significant" review — load-flow, short-circuit and stability analyses.

AMP wants PJM to vet supplemental projects to identify interdependencies with baseline projects and quantify the impacts of TO proposals on previously approved economic projects or whether they eliminate previously approved reliability projects or change cost allocations.

Dolan said many TOs create their own base cases with generation dispatch and load profiles that differ from PJM's practice, but the RTO's analysis is only applied on its own models. "There are no checks and balances to ensure that the [TO's] process is being followed and that [that] process is consistent," he said.

Dolan also expressed concern about the large number of TO projects submitted at the end of the RTEP cycle, saying PJM should establish start and stop dates for TOs to submit needs and proposed solutions, aligned with competitive windows.

He also called for standardizing the data reporting requirements for all project submissions and requiring reporting of all scenarios, models, standards and documentation used to justify and size project facilities; and a process that allows for formal submission and PJM review of alternative proposals.

Alex Stern, manager of transmission strategy and policy at Public Service Electric and Gas, said AMP's proposals were "misplaced."

Transmission Zone	Name	Cost ($ millions)	In Service Date
AEP	Darwin Bypass	$ 0.90	5/1/2018
AEP	Wyoming 765 XFR Replacement	$ 53.00	12/31/2020
AEP	Cloverdale Area Improvements	$ 54.70	12/18/2020
AEP	Jackson Road Improvements	$ 25.40	12/31/2018
AEP	Baker Station	$ 26.90	12/1/2018
AEP	Dumont Breaker Addition	$ 2.50	12/31/2020
Dominion	National Welders Substation – Switch Replacement	$ 0.36	10/30/2018
Dominion	Reeves Ave Substation – New 230kV Circuit Switcher	$ 0.50	9/30/2018
	Total	$164.26	

Newly added transmission owner supplemental projects | *PJM*

"My initial reaction is the PJM stakeholder process might be the wrong forum" for AMP's proposal, said Stern, noting FERC's Feb. 15 ruling, which he said accepted PJM's current role and declined to mandate it do more (EL16-71, ER17-179). (See *FERC Orders New Rules for Supplemental Tx Projects in PJM*.)

"FERC just advised that it doesn't believe there is any modification needed to PJM's analysis. It confirmed the acceptability and appropriateness of PJM's role with respect to planning for supplemental projects and specifically declined to require greater PJM involvement in planning for and selecting supplemental projects.

"The stakeholder process probably shouldn't be discounting FERC on this," Stern added.

"They weren't saying [PJM] couldn't do more," Dolan responded. "They were just saying, 'It's OK.'"

Internal Discussions on Sharing More Info on Tx Projects

Earlier in the meeting, Berner described the RTO's internal discussions about how it can respond to requests for more information on proposed transmission projects.

Berner said PJM is developing a tracking mechanism for identifying information shared without disclosing critical electric infrastructure information. The RTO is considering making more information available through the Planning Community portal launched in September.

The RTO expects to share its proposals within "a couple months," Berner said. Some information requests to the RTO indicate it should offer additional education on its study process, he added.

TOs Answer Questions at TEAC

At the Transmission Expansion Advisory Committee meeting later Thursday, officials of Baltimore Gas and Electric and Commonwealth Edison answered questions Dolan had posted on supplemental projects brought up for a second read. BGE, for example, said that circuit breakers slated for replacement at its Jericho and Howard substations are 47 and 27 years old, respectively, and have been the subject of expensive repairs.

Dolan appeared pleased to be receiving responses, smiling in the room when the

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PJM NEWS

PC/TEAC Briefs

Transformer Consideration Changed for Gen Deliverability

VALLEY FORGE, Pa. — PJM's plan to switch which side of a transformer is considered for cumulative ramping impact is "a win-win" because it models the system better without implicating expensive upgrades, the RTO's Jonathan Kern explained to stakeholders at last week's Planning Committee meeting.

Jonathan Kern | © RTO Insider

The RTO was proposing to include in its calculations only transformers whose lowest terminal voltage level is at least 500 kV rather than any whose high side is at least 500 kV. PJM justified the change because distribution factors for transformers are generally closer to the lower-side system they connect to than the higher side. The plan was part of a larger package of revisions to Manual 14B developed through an annual review. Stakeholders endorsed moving the proposal to the Markets and Reliability Committee but not before examining PJM's determinations.

Kern said an analysis found that two transformers — the 500/138-kV Wescosville and 500/230-kV Ladysmith — could potentially be overloaded by the change at a cost of $18 million and $25 million, respectively. He said the change would only take effect starting with the 2023 Regional Transmission Expansion Plan, an initial analysis of which doesn't show any impacts.

"There's very strong evidence for the technical change we're proposing to make here," Kern said. "To us, it appears like a win-win change. In other words, it's meeting the obvious technical intuition we have for generation delivery but also not creating any new overloads."

However, American Municipal Power's Ryan Dolan reminded everyone that no cost increases come without impact.

"I would argue that over $30 million of required upgrades wouldn't be minimal," he said.

External Capacity

PJM's Aaron Berner successfully urged stakeholders to endorse rule revisions that would allow pseudo-tied external resources wanting to offer into the RTO's capacity auctions to deliver into the energy market any additional generation beyond what's authorized for capacity.

The RTO's rules for external resources impose requirements that can limit how generation those units can offer into the Reliability Pricing Model.

"That doesn't mean though that the transmission service is not deliverable for energy use," Berner explained. "So with the addition of this language, the studies that PJM performed previously or would perform for new generation would still allow that generation to be delivered as transmission service for participation in the energy market."

The revised language was added to changes developed for Manual 12 to address pseudo-tied capacity resources. Berner fielded several clarifying questions before stakeholders requested that PJM add detail to their proposed revisions.

"The current language does not explain in detail what you explained," said James Manning with the North Carolina Electric Membership Corp.

Berner agreed to work with stakeholders on that issue, but he asked that they endorse the intent of the revisions so it can move on to the MRC.

Limiting Meetings Causing Stakeholder Strain

In explaining why proposed revisions to Manual 21 were only presented at the Planning Committee, staff said they were

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AMP Seeks More PJM Scrutiny of TO Projects

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BGE representative spoke up on the phone. He had posed the questions to Berner, who said PJM was still in collecting the necessary information and determining how to respond, but BGE then volunteered the responses. When Dolan later brought up his questions about replacing a transformer and installing two breakers at ComEd's Wayne substation, Berner deferred to a ComEd representative on the phone, who provided responses.

Earlier in the TEAC, stakeholders received first-read presentations on eight supplemental projects: six by American Electric Power totaling $163.4 million and two by Dominion, totaling $860,000. (See table, previous page.) When discussing an AEP project to replace two breakers at its Jefferson station, Berner told Dolan he didn't have answers to questions AMP had submitted and wasn't planning to bring the project back to a subsequent meeting to review the responses "unless something changes." Dolan argued that AMP had submitted questions within the timeline laid out in the TOs' recently proposed Tariff Attachment M-3, which they developed to codify the "additional detail and transparency regarding the process for planning supplemental projects" they've agreed to. It is currently circulating for review and comments.

In a discussion on a $53 million project to replace aging transformers at AEP's Wyoming substation, Dolan asked whether stakeholders would be permitted to review maintenance records on the transformers. "There's a discussion about whether maintenance records need to be made available," said Berner.

Vice President of Planning Steve Herling said PJM's reading of FERC's February order is that stakeholders should be able to replicate the TO's planning studies, "not replicate asset conditions."

"As we've been discussing, we're trying to change the progress of the supplemental upgrades as they come to PJM," Berner said at one point. "It's going to take us a little bit of time to get those specifications of the required upgrades to a point where we can present them all in a fashion that would allow identification of the issues earlier in the process, but there are a number of issues out there right now that need to be addressed. We can't delay that."

PC/TEAC Briefs

Continued from page 35

only trying to comply with stakeholder requests to limit meetings.

PJM's Jerry Bell explained the revisions, which would change how generators are tested to receive and retain capacity interconnection rights (CIRs). Stakeholders argued that the changes are wide-ranging, requiring input from experts who don't typically attend committee meetings, and asked why the considerations hadn't been put to a task force or other high-level committees.

"This is really a generation operations issue, but we're looking at it in the Planning Committee. We've got mostly transmission planners in the room here. We really need to expose this to all of the people this is really going to affect," FirstEnergy's Jim Benchek said. "These changes are pretty major."

"I don't necessarily think there's any ill intent here, but it's just that sometimes what looks to be just something for the Planning Committee has broader impacts," said Adrien Ford with the Old Dominion Electric Cooperative. She suggested that PJM's problem statement/issue charge process could have arrived at a result faster because the necessary stakeholder groups could have been identified up front.

"We're trying to balance the needs of the stakeholders where we've gotten feedback about having too many other meetings and having the agendas jammed and the days of the week jammed with other meetings," said Ken Seiler, who chairs the Planning Committee. He said he would confer with the chairs of the Operating and Market Implementation committees about how to handle the requests.

Stakeholders noted several concerns with the proposal, which would eliminate June from the summer testing period (leaving July through August) and require simultaneous testing of all resources at a plant except wind and solar units. They would have to be able to start within five minutes.

"If you were to call on all the units at a plant and apply the test simultaneously, the start-up costs could get quite expensive," Benchek said, adding that his company didn't favor the reduced testing period either.

Solar and wind would be exempt because they use their average capacity factor during the peak hours included in the testing, but all capacity factors will be determined by calculating the median rather than average performance going forward. Bell confirmed those calculations won't become fully effective until 2021/2022.

Mike Borgatti with Gabel Associates was concerned that the proposed language changes didn't adequately enunciate that units' capacity factors wouldn't be affected for three years.

Bell also walked stakeholders through analysis that shows that the 650 MW of non-dispatchable hydro generation might be overstated by 520 MW because the expected capacity factor of 20% shows that 130 MW is predicted to be available.

AEP Project Removed from RTEP Modeling

American Electric Power's portion of Duff-Rockport-Coleman project has been placed on hold and will not be modeled in the 2018 RTEP, PJM told the Transmission Expansion Advisory Committee on Thursday.

Robert Bradish, AEP's vice president of transmission grid development, informed PJM of the change in a letter Feb. 20. Bradish said the supplemental project was proposed to address voltage stability limitations and eliminate the special protection scheme at the Rockport plant by interconnecting the Rockport 765-kV station with the MISO Duff-Coleman 345-kV market efficiency project.

"The current generation situation at Rockport plant is quite different from the situation when this supplemental project was included in the 2015 RTEP," Bradish wrote. "There is currently significant uncertainty regarding generation-related conditions which may affect future operation of the Rockport units. Certain of these generation conditions can only be addressed through coordination with third parties, regulatory proceedings and other circumstances outside of AEP's control."

Retirement Studies Update

PJM has completed reliability analyses on retirements at six generating stations and is conducting reviews for three others.

The retirements of Buggs Island 1 and 2 (138 MW), Bremo 3 and 4 (227 MW), and Bellemeade CC 1 (265.7 MW) are all effective April 16; Possum Point 3 and 4 (317.7 MW) and Chesterfield 3 and 4 (262.1 MW) are both scheduled for Dec. 1. PJM said it has asked Dominion Energy, the transmission owner for all the plants, to perform additional analysis to identify any required upgrades.

Jerry Bell | © RTO Insider

PJM said it identified no impacts from the scheduled May 3 closing of Evergreen Power United Corstack (25 MW) in Met Ed.

It is conducting analyses on the Morris Landfill Generator (1.9 MW) in ComEd and the Reichs Ford Road Landfill Generator (1.7 MW) in APS, both set for May 31, as well as FirstEnergy's Pleasants Power Station 1 and 2 (1,278 MW), scheduled for Jan. 1, 2019. (See *FirstEnergy Shutting down Unsold Coal Plant*.)

Market Efficiency Update

PJM planners have selected a $25.4 million proposal by Baltimore Gas and Electric to address constraints on the Conastone-Graceton-Bagley 230-kV corridor after finding it cleared their reliability and cost/constructability analyses. The project (proposal 5E), which involves reconductoring and upgrades to equipment at the Conastone and Windy Edge substation, is expected in service in 2021. It will be recommended for approval at the Board of Managers meeting in April.

Planners said they won't be recommending any market efficiency projects in the PPL zone after seeing the projected congestion benefits from the proposed Susquehanna–Harwood drop by about half under the base case because of a lower load forecast and changes in generation expansion since the start of the 2016/17 project window.

PJM is now developing assumptions for its 2018/19 RTEP long-term window, which it expects to open between November and February 2019.

Officials also said they expect to open a 60-day reliability project window in May or June.

— Rory D. Sweeney & Rich Heidorn Jr.

PJM News

RTO Resilience Filings Seek Time, More Gas Coordination

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PJM Seeks More Coordination with Pipelines, LDCs

PJM says its grid is stable and secure but urged FERC to demand changes to improve identification and mitigation of current vulnerabilities and future grid resilience challenges. The RTO also touted itself as a good example in several areas and asked FERC to make other grid operators follow its lead.

The RTO's 84-page response also offered revisions to FERC's proposed definition of resilience: "The ability to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to and/or timely recover from such an event." The RTO said the definition needs to "accurately reflect" grid operators' capabilities without imposing "additional liabilities and … a new duty and standard of care." FERC should also stipulate that enhancing resilience is one of grid operator's responsibilities within regional planning, the RTO said, and that the commission has authority over resilience under its responsibility under the FPA to ensure "just and reasonable rates, terms and conditions of service."

While acknowledging the risks of high-impact, low-frequency events, PJM also warned about "addressing vulnerabilities that evolved over time and threaten the safe and reliable operation." It asked that FERC develop a process for grid operators to receive a review and feedback on their threat and vulnerability assessments based on national security information the commission has access to that grid operators don't.

PJM said it has already begun addressing flaws within its operating reserve, shortage pricing, black start, energy price formation, and integration of DERs and storage. (See "Stakeholders Challenge PJM Decisions on Reserve-Shortage Identification," PJM OC Briefs.)

Restoration Needs

Interestingly, PJM also asked that it be required to develop procedures to "permit non-market operations during emergencies, extended periods of degraded operations or unanticipated restoration scenarios … including provisions for cost-based compensation when the markets are not operational or when a wholesale supplier is directed to take certain emergency actions by PJM for which there is not an existing compensation mechanism."

PJM said work like it's doing to require dual-fuel capability at all black-start units should be extended throughout the country to identify "critical restoration units" and fuel-assurance criteria for them. (See "Black Start RFP," PJM Operating Committee Briefs: Feb. 6, 2018.)

Pipeline Coordination

PJM also sought help in improving information sharing and coordination with gas pipelines, asking FERC to:

- Require information sharing by pipelines by revising the "voluntary nature" of Order 787;
- "Encourage" pipelines to share their threat and vulnerability analyses with grid operators, along with real-time contingency modeling and restoration-planning coordination;
- Encourage development of additional pipeline services tailored to the flexibility needs of gas-fired generation "beyond today's traditional firm/interruptible paradigm";
- Work with the Transportation Security Administration and the Pipeline and Hazardous Materials Safety Administration to improve "harmonization of cyber and physical security standards between the electric sector and the natural gas pipeline system"; and
- Support more communication and coordination with local distribution companies supplying generators, perhaps by imposing obligations on local distribution companies through interstate pipeline tariffs.

Grid operators should also be required to show how they're coordinating with other

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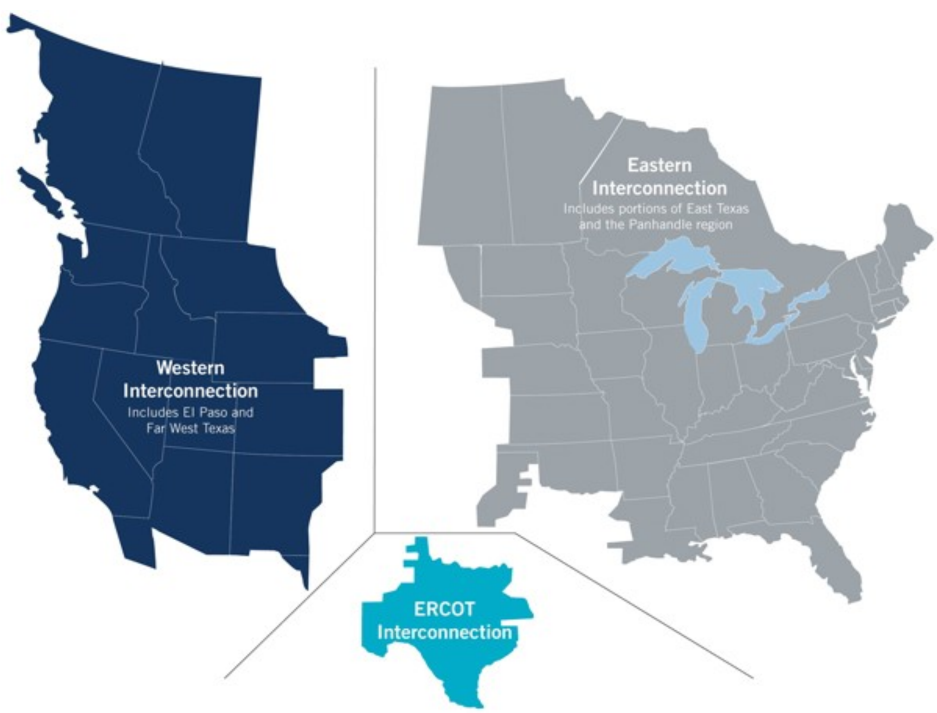


ERCOT is exempt from FERC's rules for RTOs and ISOs but is subject to NERC reliability standards. | ERCOT

SPP NEWS

SPP Board, Members to Meet on Mountain West

SPP has scheduled an executive session of its Board of Directors and Members Committee for today to discuss admitting Mountain West Transmission Group's members into the RTO.

The meeting is being held at an undisclosed location. SPP has often used Dallas/Fort Worth International Airport to meet for its ease of access and onsite hospitality facilities.

SPP CEO Nick Brown told the Board of Directors in January the RTO was hoping to hold a "decision meeting" for members at the end of February for those stakeholders "who need to engage outside counsel and consultants, who previously were not engaged in the debate."

SPP and Mountain West members have been meeting behind closed doors since October. SPP COO Carl Monroe told stakeholders in January that a small negotiating team had been working to resolve a subset of "real contentious" issues. The Mountain West entities have suggested several governance changes important to their side of the footprint. (See *SPP, Mountain West Resolving 'Contentious' Issues*.)

Brown said SPP's primary goal for 2018 is integrating Mountain West. "Our goal is to get it over the line in early 2018," he said.

With members primarily serving Colorado, Wyoming and Nebraska, Mountain West began discussing joining or creating an RTO in 2013. It announced in January 2017 it was pursuing membership in SPP, and discussions entered a public phase in October. (See *SPP, Mountain West Integration Work Goes Public*.)

The two entities are working on an Oct. 1, 2019, target date for membership.

Record $6.9M in January for Market-to-Market Payment

SPP's Riverton-Neosho-Blackberry flowgate — quickly becoming recognized by just its 5375 ID — was binding for 350 hours in January, resulting in a record $6.9 million market-to-market (M2M) payment from MISO. The Kansas-Missouri border flowgate was responsible for $6.2 million of the charges, more than all the flowgates combined in any other single month.

SPP has accumulated almost $44 million in M2M payments since the two RTOs began the process in March 2015. MISO has not had a month in its favor since last July and only nine overall.

SPP staff told the Seams Steering Committee on March 7 that they have been implementing an "enhanced shadow price override" non-monitoring RTO process on swing-related flowgates since Jan. 4. The two RTOs are also considering implementing a "monitoring RTO reverse role," where MISO would control the physical flow on a flowgate and SPP control the market flow.

Permanent and temporary flowgates were binding for 632 hours in January, SPP staff told the committee.

Staff also briefed the committee on FERC's April 3-4 technical conference related to how SPP, MISO and PJM coordinate generator interconnection studies on projects near their seams. The commission called the conference to address issues raised in an October complaint by EDF Renewable Energy, which contends that inconsistencies and a lack of clarity in the RTOs' rules for "affected systems" interferes with developers' ability to judge the commercial viability of proposed projects. (See *FERC Orders Review of PJM, MISO, SPP Generator Studies*.)

SPP, AECI Wait on Joint Study Scope

SPP and Associated Electric Cooperative Inc. last week failed to reach an agreement with their stakeholders on a scope for a 2018 joint study during an Interregional Planning Stakeholder Advisory Committee meeting. Another IPSAC will likely be scheduled in a few weeks, giving members a chance to review the draft scope with their companies and providing staff additional time to revise its models.

SPP staff said they had drafted a scope that identified needs from its 2018 near-term assessment that are "electrically significant to the SPP-AECI seam."

The RTO plans to use its near-term assessment models, which have already been approved by its stakeholders. AECI regularly participates in the near-term model-building process, which allows the two entities "to explore a broader set of projects which could potentially provide benefit to both systems," SPP staff said.

— Tom Kleckner

Position	FG	Description	Control Zone	Grand Total	Direction
1	SWPP_5375	Neosho - Riverton 161kV ftlo Neosho - Blackberry 345kV	EDE, WR	$24,329,524.53	MISO Pays SPP
2	SWPP_5501	CBLUFFS - SUB3456 345 kV ftlo ROLLHILS - MADNCO 345 kV	MEC, OPPD	$3,273,359.90	MISO Pays SPP
3	MISO_1967	Arkansas_PleasantHills500kv_ftlo_Arkansas_Mabelvale500kv	EAI	$2,560,809.13	MISO Pays SPP
4	SWPP_5577	Nashua 345/161 kV Transformer ftlo Nashua - Hawthorn 345kV	KCPL	$2,353,820.25	MISO Pays SPP
5	SWPP_23199	CBEC - Sub 1206 ftlo Council Bluffs - Sub 3456 345kV	OPPD, MEC	$1,853,298.72	MISO Pays SPP
6	SWPP_6126	S1226-Tekamah 161kV flo S3451-Raun 345kV	OPPD, MEC	$1,647,453.33	MISO Pays SPP
7	SWPP_21945	Beulah - Haliday 115kV ftlo Antelope Valley - Charlie Creek 345kV Ckt 2	WAUE, MDU	-$1,631,418.08	SPP Pays MISO
8	SWPP_21012	TEMP03 Fort Smith 500/161 kV XFR (flo) Fort Smith 500/345 kV XFR	OKGE	$1,598,072.57	MISO Pays SPP
9	MISO_6012	PR_ISLD - NROCH 345 kV	NSP/SMP	-$1,533,899.25	SPP Pays MISO
10	MISO_22761	DKSN_ND - Matthson 115KV flo Belfield - Charlie Creek 345 KV	MDU, WAUE	-$1,465,953.28	SPP Pays MISO

Top 10 flowgates since M2M go-live | *SPP*

SPP NEWS

Xcel, NPPD Lose Z2 FERC Complaints

By Tom Kleckner

FERC last week rejected separate complaints by the Nebraska Public Power District and Xcel Energy over billed charges under Attachment Z2 of SPP's Tariff.

Filing on behalf of its Southwestern Public Service affiliate, Xcel alleged SPP's assignment of $12.8 million in credit payment obligations under Z2 and $485,000 in zonal charges violated service agreements with SPS and the filed rate doctrine, and that the RTO's implementation of Z2 violated the Tariff's "but for" test (EL18-9).

NPPD complained SPP misinterpreted its Tariff and improperly billed the utility for 86 Z2 revenue credit obligations and said the misinterpretation will subject it to future monthly charges under regionwide and zonal rates eligible for recovery (EL17-86).

Attachment Z2 assigns financial credits and obligations for sponsored transmission upgrades. The RTO last year completed a resettlement of the Z2 revenue, crediting amounts for March 2008 to August 2016, a move made necessary because of corrections and true-ups to the data that were identified before the first settlement of the charges. (See "More Z2 Woes; SPP to Resettle 9 Years of Data," *SPP Markets and Operations Policy Committee Briefs: July 11-12, 2017*.)

FERC has consistently sided with SPP in member complaints to the commission. It denied requests by several members to rehear FERC's 2016 order waiving the one-year limit for adjusting Z2 payment obligations and revenue distributions for transmission projects. It also partially granted Kansas Electric Power Cooperative's complaint in a separate transmission dispute with SPP, denying some claims and setting settlement judge procedures on others. (See *FERC Rejects SPP Change on Network Resource Upgrades*.)

| Aristotle Buzz

FERC: Xcel Should Have Been Aware of Z2 Costs

The commission dismissed Xcel's argument that SPS' service agreements with SPP resulted from the RTO's aggregate transmission service study process, were accepted by the commission and should have reflected SPS' final cost responsibility as part of the filed rate. Xcel asserted that when SPS executed the resulting service agreements with SPP, the agreements should have contained all of the final responsible upgrade costs.

But FERC found the aggregate study reports alerted Xcel to the potential for SPS to be directly assigned costs for upgrades later determined to be necessary to support the transmission service request (TSR) in SPS' agreements. It noted SPP was developing the Z2 revenue crediting mechanism when it provided Xcel with study reports and, "therefore, could not provide accurate estimates."

The commission also rejected Xcel's allegation that SPP's assignment of costs violated Attachment Z2 and the filed rate doctrine, finding that Xcel misinterpreted the RTO's application of the "but for" test. FERC found SPP's methodology to be "reasonable" in determining whether a TSR makes subsequent use of creditable upgrades and that the "but for" test to determine credits under Attachment Z2 was a "reasonable and practical application."

SPP's Tariff Interpretation Correct

FERC also found SPP correctly interpreted its Tariff by classifying more than $860,000 in upgrades identified in NPPD's complaint as service upgrades eligible for base plan funding cost allocation. The commission said the upgrades were initially determined to be necessary for generator interconnection requests, and the costs were directly assigned to customers "consistent" with interconnection procedures and the Tariff's *pro forma* interconnection agreement, making them creditable upgrades.

The directly assigned upgrade costs became eligible to be recovered through revenue credit payments that made "subsequent use of the upgrades," the commission said. In implementing the Z2 crediting process, SPP identified additional creditable upgrades subsequently used by previously studied TSRs and associated credit payment obligations, FERC said.

The commission said those obligations became eligible for base plan funding under the Tariff's cost allocation rules and were included in the rolled-in allocation of costs to transmission customers through the regionwide and zonal rates.

"Therefore … these costs were properly allocated under base plan funding," FERC said, in rejecting NPPD's assertions that SPP should allocate the costs differently.

SPP NEWS

RTO Resilience Filings Seek Time, More Gas Coordination

Continued from page 37

"critical interdependent infrastructure systems" like telecommunications and water utilities, PJM said.

— Rory D. Sweeney

SPP: One-Size-Fits-All Approach 'Not Appropriate'

SPP agreed with the commission's approach to evaluating resilience, saying FERC should continue its holistic approach and "consider the roles and relationships all participants in the electric industry, not just RTOs and ISOs, have with respect" to the grid's resilience.

In its 21-page response, SPP wrote that it "agrees with the commission's premise that a one-size-fits-all approach to resilience is not appropriate given the differences that can exist between the various regions."

It stressed the importance of weighing the potential benefits against the costs in considering changes to current requirements. "Changes to requirements to address resilience could increase the costs of transmission owners' systems, and those increased costs would ultimately impact transmission customers and their end-use customers," SPP said.

"Accordingly, SPP respectfully submits that the perspectives and practices of non-RTO entities, including, without limitation, transmission owners, generation owners and state regulators, should be sought out and considered, as different participants in the electric industry can provide valuable insight regarding their experiences."

The RTO said FERC's definition of resilience is "a reasonable way to capture the concept" and said it is consistent with a framework NERC is using. The reliability organization's Issues Steering Committee told the Board of Trustees in February that most resilience definitions have two common elements: that resilience is "time-dependent" and differs from business-as-usual operations, and that it cannot be measured in a single-unit metric. (See "FERC's McIntyre Says Resiliency Still of Interest in DC," *NERC MRC/Board of Trustees Briefs: Feb. 7, 2018*.)

The committee's framework includes four outcome-focused capabilities:

- Robustness: the ability to absorb shocks and continue operating.
- Resourcefulness: the ability to skillfully manage a crisis as it unfolds.
- Rapid Recovery: the ability to restore services as quickly as possible.
- Adaptability: the ability to incorporate and improve with lessons learned from past events.

SPP said its approach is based on "(1) resolving potential problems before they have a chance to disrupt daily operation … and (2) restoring daily operation as quickly and seamlessly as possible in the event a disruption does occur."

It cited the resilience benefits of new transmission. "The construction of new transmission facilities pursuant to modern design standards enhance the robustness of the system," SPP said.

"Continually evaluating risk and upgrading equipment, tools and procedures … facilitates rapid recovery by minimizing the extent and impact of disruptions."

SPP said its approach remains adaptive, "as it is based on historical experience … combined with forward-looking evaluation of new risks and evolving technologies used in the industry."

— Tom Kleckner

FERC & FEDERAL NEWS

Court Backs FERC in Hydro License Dispute

By Rich Heidorn Jr.

FERC adequately explained why it limited Duke Energy Carolinas to a 40-year extension on the Catawba-Wateree hydro project, the D.C. Circuit Court of Appeals ruled last week.

Duke had sought a new 50-year license for the project, which includes 11 developments on hundreds of miles of the Catawba and Wateree rivers in North Carolina and South Carolina; its original 50-year license expired in 2008. FERC issued the 40-year license in 2015, concluding that construction and environmental measures under the new license were "moderate" (Project 2232-522).

The company asked the court to overturn the ruling, arguing it was similarly situated to applicants that had received 50-year extensions, making the commission's order "arbitrary and capricious."

The court declined to second guess the commission, noting the "narrowly circumscribed" role for the courts in ruling on hydro matters. "According due deference to the commission's expertise in determining whether measures under a license are moderate or extensive and to its interpretation of its precedent and policy choices, we deny the petition for review," it wrote (16-1296).

The commission generally issues a 30-year license for projects with "little or no" new development, capacity or environmental mitigation; a 40-year license for projects requiring "moderate" investments; and a 50-year license for projects involving "extensive" measures.

Duke applied for a new license after reaching an agreement with 70 entities that specified measures it would take under a renewal.

In its request for rehearing, Duke argued that FERC had failed to consider the costs of its investments, saying it had spent about $54 million on construction required by the agreement and $111 million in other relicensing costs.

FERC responded it does not rely on a "a strictly quantitative analysis" because "cost estimates can fluctuate widely over time." It also said Duke's cost data were "not reliable."

"In response to commission staff's request to simply update the cost estimates … Duke Energy instead filed new estimates — unsupported by any explanation," the commission said, noting the company included a $40 million gate instead of the $10 million bladder dam called for in the license order.

The court cited FERC's observation that Duke had not claimed it could not recoup its costs within 40 years.

"Further, the commission noted that some of Duke Energy's cost estimates were not fully supported, or were inconsistent with the new license, because it was unclear that all the enhancement and mitigation measures are new measures," the court said. "Duke Energy's effort to avoid the plain meaning of the staff request to update the cost estimates is unpersuasive; as license applicant, it had every incentive to explain the basis for its cost estimates, and it cannot prevail by shifting the burden of clarification to the commission."

McIntyre Discloses Brain Tumor Surgery

FERC Chairman Kevin McIntyre disclosed Sunday that he underwent successful surgery for a brain tumor that was discovered last summer.

The disclosure, made in a statement posted on FERC's website, appears to explain the dramatic difference in McIntyre's appearance between his Senate confirmation hearing in September and his swearing in in December, after his hair — apparently having been partly shaved — was beginning to grow back.

FERC Chairman Kevin McIntyre at his Senate confirmation hearing in September 2017 (right) and his testimony before the Senate in January (left), after his hair — apparently having been partly shaved — was beginning to grow back. | © *RTO Insider*

The health issues also may have played a part in McIntyre's delayed arrival at FERC. He took office on Dec. 7, more than a week after Commissioner Richard Glick; both were confirmed by the Senate on Nov. 2.

McIntyre said he issued the statement because of inquiries about his health. He said the tumor was discovered unexpectedly last summer. "Through an incidental finding, i.e., a medical issue discovered by accident, I was diagnosed with a brain tumor. I was very fortunate that the tumor was relatively small, that I had no symptoms and that I was otherwise in excellent health.

"Thereafter, I underwent successful surgery, followed by the post-operative treatment that is the standard of care for my situation. I was advised at the time that, with the surgery and subsequent treatment behind me, I should expect to be able to maintain my usual active lifestyle, including working full time, and that expectation has proven to be accurate."

The chairman expressed gratitude for the support he received from those who had been aware of his situation "especially those in the White House, Congress and the FERC."

He said he did not intend to provide further details or updates "for reasons of personal and family privacy."

"I am grateful that my health is now stable and that I am able to devote my full energy to serving the American public every day as chairman of the FERC and continuing to work to earn the trust that has been placed in me," he said.

McIntyre joined FERC after two decades at Jones Day, where he represented energy clients in administrative and appellate litigation, compliance and enforcement matters, and corporate transactions.

— Rich Heidorn Jr.

COMPANY BRIEFS

Tradewind Sells 300-MW Kansas Wind Farm to Enel Green Power

Diamond Vista | *Tradewind Energy*

Tradewind Energy has sold a 300-MW wind project under construction in Kansas to Enel Green Power North America.

The Diamond Vista wind farm has agreements to supply 84 MW of power to the Tri-County Electric Cooperative in Oklahoma, and 100 MW apiece to City Utilities of Springfield, Mo., and Kohler. It's expected to be finished by the end of the year.

More: *Kansas City Business Journal*

Hydro-Quebec Gets Permit for Canadian Portion of Northern Pass

Hydro-Quebec said on March 6 that the National Energy Board has granted it a permit to build and operate the part of the Northern Pass transmission project that's in Canada.

The project, which Hydro-Quebec is building in conjunction with Eversource Energy in the U.S., was the winner of Massachusetts' clean power solicitation, but its fate is in jeopardy because the New Hampshire Site Evaluation Committee denied it a permit.

Massachusetts has given the project until March 27 to get a permit from New Hampshire. If it doesn't, the state will award its clean power solicitation to New England Clean Energy Connect, which involves Hydro-Quebec and Avangrid's Central Maine Power subsidiary. (See *Mass. Picks Avangrid Project as Northern Pass Backup*.)

More: *Hydro-Quebec*

Ameren Hires First Chief Digital Information Officer

Amirthalingam

Ameren said March 5 that Bhavani Amirthalingam has joined it in the newly created position of senior vice president and chief digital information officer. In that post, she will focus on accelerating the company's customer-focused digital innovation.

Amirthalingam comes to Ameren from Schneider Electric, which specializes in global energy management and automation solutions that integrate technology, software, and services. She has also served as the chief information officer for World Wide Technology, a technology integrator that helps its customers evaluate, architect, and implement advanced technology.

"Bhavani is a passionate, results-oriented leader who will help us achieve and maintain excellence in running our core information technology operations while at the same time accelerating innovation and transformation of our business by leveraging technology," said Martin Lyons Jr., Ameren's executive vice president and chief financial officer.

More: *Ameren*

SWEPCO Accuses Group of Misleading on Wind Catcher

Southwestern Electric Power Co. on March 6 accused an organization that calls itself Protect Our Pocketbooks of "presenting misleading information to the public" to promote opposition to the Wind Catcher Energy Connection project in Arkansas and Louisiana. The organization "does not reveal the names of its backers or the sources of its substantial funding," SWEPCO said.

SWEPCO has reached an agreement with the Arkansas Public Service Commission General Staff, the Arkansas Attorney General, Walmart Stores and Sam's West over the project and on Feb. 20 filed a motion, along with the other parties, asking the PSC to approve the agreement. Louisiana regulators have been considering the project since late July.

SWEPCO will own 70% of Wind Catcher, a $4.5 billion project that includes the acquisition of a 2,000-MW wind farm being built in the Oklahoma Panhandle and the construction of a 360-mile transmission line to connect the wind farm to the grid in the Tulsa, Okla., area. Public Service Company of Oklahoma, which like SWEPCO is a subsidiary of American Electric Power, will own the remaining 30%.

More: *Arkansas Times*; *SWEPCO*

Fitts Joins Schiff Hardin From Debevoise & Plimpton

Schiff Hardin said March 5 that energy lawyer Sarah A.W. Fitts has joined it as a partner in its New York office.

Fitts represents clients in mergers and acquisitions, project finance, and restructurings, helping them navigate the challenges presented by joint ventures and other complex governance arrangements. Prior to joining Schiff Hardin, she was a partner at Debevoise & Plimpton, where she was the co-chair of its Energy & Natural Resources Group.

A key focus area for Fitts and Schiff Hardin's Energy Industry Team is the infrastructure development spurred by the growth of electric vehicles and their reliance on the grid. The team is advising companies on how to develop, finance, and build EV infrastructure projects, as well as how to deal with the environmental and regulatory concerns that the projects raise.

More: *Schiff Hardin*

Xcel Makes Filings Detailing Tax Cuts in Wisconsin, Minnesota

Xcel Energy has made regulatory filings saying its savings from the Tax Cut and Jobs Act will amount to $133 million for its Minnesota electric operations and $25 million to $30 million for its Wisconsin electrical operations.

"We intend to ensure our customers receive the full value of the tax reform benefits," Xcel said in a March 2 filing with the Minnesota Public Utilities Commission.

An Xcel spokeswoman said the company's goal in Wisconsin is to maintain or decrease its rates beginning in 2020.

More: *Star Tribune*; *Leader-Telegram*

Federal Briefs

House Votes to Ease Coal Waste Plants' Emission Requirements

The House of Representatives on March 8 passed a bill that would ease emissions requirements on power plants that burn coal waste for fuel.

Under the Satisfying Energy Needs and Saving the Environment Act, those plants would have to control emissions of either hydrogen chloride or sulfur dioxide, but not both.

Eighteen power plants, including three in Pennsylvania, would benefit from the bill, which does not have a companion act in the Senate. Without a change in law, those plants likely will be closed by 2019 when a waiver for them expires, said Sean Lane, executive vice president for government affairs at Olympus Power.

More: Bloomberg BNA

A Third of Top EPA Hires Were Corporate Lobbyists or Lawyers

About a third of the 59 EPA hires tracked by the Associated Press over the past year worked as registered lobbyists or lawyers for corporate clients, including chemical manufacturers and fossil fuel producers.

Most have signed ethics agreements saying they won't take part in proceedings involving their former clients while working for EPA, but three have gotten waivers.

Those three are among 24 key Trump administration officials who have obtained ethics wavers from White House counsel Don McGahn, according to a review of documents by the AP. The Obama administration issued nearly 70 waivers to executive branch officials in eight years.

More: The Associated Press

DOE Wants to Develop New Coal Plants with Carbon Capture Funds

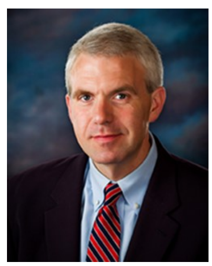
The Department of Energy's proposed 2019 budget calls for funding an effort by government laboratories to design more efficient coal plants with money that would have gone to advancing carbon capture technology.

Under the budget, the labs would be required to complete at least two designs for smaller, modular coal plants that produce more power from less coal. To help pay for that, the Trump administration is proposing reducing by 80% the $196.3 million budgeted by Congress last year for carbon capture research and development for carbon capture.

The Obama administration also supported developing so-called "High Efficiency Low Emissions" coal plants but wanted them to include carbon capture technology, said Tarak Shah, a senior adviser in DOE under President Barack Obama.

More: Houston Chronicle

NARUC Names Presley, Fedorchak Vice Chairs of Gas Committee


Presley

The National Association of Regulatory Utility Commissioners said Wednesday that it has appointed Mississippi Public Service Commission Chair Brandon Presley and North Dakota Commissioner Julie Fedorchak to serve as the vice chairs of its Committee on Gas.

NARUC recently appointed New York State Public Commissioner Diane X. Burman to be chair of the Committee on Gas.

NARUC said the Committee on Gas uses panel discussions and educational sessions to foster awareness and understanding of issues affecting the safe, efficient and economical transportation, distribution and sale of natural gas. Its members work closely with FERC, the Department of Energy and the Department of Transportation.

More: NARUC

Residential Solar Battery Retrofits Eligible for Tax Credits

A letter released by the Internal Revenue Service on March 2 indicates that battery systems added as retrofits to residential solar generation systems qualify for federal solar tax credits, according to a GTM Research analyst.

In the letter, the IRS found that the battery, inverter, wiring, and software that were added to an existing rooftop solar system, set up so that they store energy only from the solar system and are otherwise available to respond to power outages or to reduce overall load, are subject to the 30% investment tax credit (ITC).

The letter said that it's directed "only to the taxpayer who requested it" and that "it may not be used or cited as precedent." Still, GTM Research Analyst Brett Simon said that it's "important because it reveals how the IRS views retrofits and could lead to a future guidance that allows for all retrofits of storage to take the ITC."

More: Greentech Media

Report: US Grid-Connected Energy Storage Market Forecast to Take Off

More than 1,000 MWh of grid-connected energy storage will be deployed in the United States this year, according to a report released March 6 by GTM Research and the Energy Storage Association.

The total is nearly equal to the 1,080 MWh deployed between 2013 and 2017 and would represent a major acceleration from the fourth quarter of 2017, when 100 MWh of storage was deployed.

"Falling costs and favorable policies will be among the core drivers of the market's breakout 2018," said Ravi Manghani, GTM Research's director of energy storage. "It's not hard to imagine that every solar RFP by the end of the year will include storage."

More: GTM Research

2nd Circuit Hears New York ZEC Appeal

The 2nd U.S. Circuit Court of Appeals on Monday heard oral arguments in an appeal of a judge's decision to dismiss a suit against New York's zero-emission credits program.

In filing the appeal, the Electric Power Supply Association and members Dynegy, Eastern Generation and NRG Energy joined Roseton Generating and Selkirk Cogen Partners in arguing that some generators would lose millions in revenue because the subsidized nuclear plants would suppress NYISO capacity and energy prices.

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

ClearView Energy Partners issued a statement on Monday's arguments saying that at least two of the three appellate judges appeared skeptical of petitioners' preemption claims that the ZEC program infringes on FERC's exclusive jurisdiction over wholesale markets.

Miles Farmer of the Natural Resources Defense Council said in a blog post that the 2nd Circuit will likely provide the final say on the validity of New York's ZEC program under federal law.

New York's Clean Energy Standard and its provisions for subsidies for nuclear plants are also being challenged in state court. The Albany County Supreme Court in January rejected the state's motions to dismiss outright a lawsuit challenging the ZEC program. (See *New York Court to Consider ZEC Challenge*.)

– Michael Kuser

STATE BRIEFS

ARIZONA

SRP's Board Agrees to Settlement of Tesla Lawsuit

Salt River Project's board of directors on March 5 voted to agree to a settlement to the lawsuit that SolarCity brought against it. Under the settlement, SRP would buy a massive battery from SolarCity and give incentives to customers who want to install batteries at their homes.

SolarCity, which is now a Tesla subsidiary, sued SRP in Arizona District Court in 2015 after the utility imposed new rates on customers with solar panels, accusing it of "anticompetitive and tortious conduct designed to eliminate solar competition." SRP tried unsuccessfully to have the case thrown out on immunity grounds, saying that it can't be charged with antitrust law violations because it's a public utility. It appealed to the 9th Circuit Court of Appeals and then to the U.S. Supreme Court.

Under the settlement, Tesla would drop its challenge to the solar rates, and SRP would drop its appeal to the Supreme Court.

More: *The Republic*

CALIFORNIA

FERC Approves CAISO Interconnection Changes

New generation resources waiting to interconnect to the CAISO grid will have an additional year of time in the interconnection queue under rule changes approved by FERC on March 9.

CAISO argued that allowing projects to sit in the queue for an additional year will allow them more time to compete for power purchase agreements, a required milestone. This will allow increasingly complex projects such as renewable-storage combinations to remain in the queue that otherwise might be dropped.

Another provision that FERC approved shortened the interconnection request window to the two weeks of April from the entire month and lengthens the validation period to account for increasing project complexity. This gives CAISO an additional two weeks to conduct validation without impacting study schedules, FERC said.

More: *ER18-626*

NEW JERSEY

Gov. Murphy Blasts JCP&L Storm Recovery

Gov. Phil Murphy last week scolded Jersey Central Power & Light, calling its response to recent winter storms "embarrassing."

"As I have said throughout the week, JCP&L's preparation for and response to the past week's weather events is completely unacceptable," Murphy said in a statement. "I will not accept any of the company's excuses for why thousands of New Jerseyans continue to be without power."

Nearly 50,000 customers remained without power as of Saturday following two nor'easters that hit the region over 10 days. JCP&L said Monday it expected the remaining 2,300 customers to be restored by late that evening. It said 528,000 customers lost power due to heavy, wet snow and strong winds.

More: *The Philadelphia Inquirer*

Former BPU President Mroz Stepping down Next Month

Richard Mroz said in a letter to Gov. Phil Murphy that he will resign from the Board of Public Utilities effective April 14. In the letter, the former BPU president said he would return to the private sector but stay in the energy, utility, and infrastructure industries.

The departure of Mroz, a Republican who supported former Gov. Chris Christie's energy policies, will leave the board with two Democratic members and two Republican members. It also gives Murphy a chance to appoint a board member more supportive of the renewable energy policies he wants implemented.

More: *NJ Spotlight*

NEW MEXICO

AG Files Lawsuit Accusing Vivint Of Deceptive Sales Tactics

Attorney General Hector Balderas on March 8 filed a lawsuit in state District Court accusing Vivint Solar of using deceptive sales tactics to defraud residents and jeopardize their home ownership.

The company said it takes the allegations seriously but thinks the lawsuit is without merit. Vivint has settled similar lawsuits brought by prosecutors in other states.

More: *Santa Fe New Mexican*