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Chatterjee: 'We've Moved Past' DOE NOPR

Gavels Last FERC Open Meeting as Chair

By Michael Brooks

WASHINGTON — FERC Chairman Neil Chatterjee on Thursday defended his call for interim price supports for coal and nuclear plants as a response to Energy Secretary Rick Perry's grid resiliency proposal.

In remarks to reporters after FERC's open meeting, Chatterjee expressed frustration with the reaction his plan has received from industry stakeholders. He said his critics were still debating the department's Notice of Proposed Rulemaking — which calls for RTOs and ISOs with energy and capacity markets to pay generators with 90-day supplies of onsite fuel their full operating costs — and not his idea to provide a "lifeboat" for baseload plants while FERC considers the NOPR.

Chatterjee was asked about discussions regarding the NOPR at the National Association of Regulatory Utility Commissioners' Annual Meeting in Baltimore this week. "This is part of the confusion and why people are having the outsized reactions that they're having," he responded. "That entire debate at NARUC was predicated on the NOPR that Perry has submitted. What I'm sitting here talking about is what we've

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FERC Pipeline Approval Attracts Celebrity Protest (p.32)

NERC: Natural Gas Dependence Alters Reliability Planning

By Tom Kleckner

Planners must give more weight to potential pipeline outages in electric reliability reviews, NERC said in a report last week.

"In light of the power sector's rising reliance on natural gas, the loss of gas facilities must be added to the list of potential extreme contingencies used to measure system reliability impacts," John Moura, NERC's director of reliability assessment and system analysis, said in a statement announcing the report.

The report shows the impact of natural gas delivery disruptions will vary depending on the location and density of infrastructure. But the reliability authority says mitigation strategies are available to reduce the poten-

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Cauley Resigns; NERC Launches Search for Replacement

By Rich Heidorn Jr.

NERC announced Monday that its Board of Trustees has accepted the resignation of CEO Gerry Cauley, effective immediately, following his arrest for domestic abuse.

The organization said General Counsel Charles Berardesco will continue to serve as acting CEO while the board seeks a search firm to recruit a replacement.

"NERC has a talented staff and an experienced leadership team that is well-equipped to continue the forward momentum on key initiatives," Board Chair Roy Thilly said in a statement. "I am confident we will continue to meet milestones and expectations going forward. NERC remains committed to maintaining the reliability and resilience of the bulk power system."

A NERC spokeswoman declined to comment when asked whether Cauley would receive any severance payment. "Any personnel action is confidential," she said.

NERC CEO Gerry Cauley (second from right, background) and General Counsel Charles Berardesco (to Cauley's left) attend a NERC board meeting in New Orleans on Nov. 9, hours before Cauley's arrest for domestic abuse. | *NERC*

NERC had placed Cauley on a leave of absence after his arrest for battery, a misdemeanor, for allegedly assaulting his estranged wife in the early morning of Nov. 10. The police report documenting his arrest states that his wife, Jean Cauley, sustained bruises and scratches and was experiencing a great deal of pain in her back.

The report quoted Jean as saying he attacked her after she discovered him having

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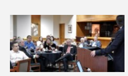

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Correction

An article in the Oct. 17 edition was inconsistent in its descriptions of the units used by FERC in its supplemental environmental impact statement for the Southeast Markets gas pipeline project. (See *FERC Chair: Court Ruling Won't Change Pipeline Reviews*.) The story should have made clear the units were "million metric tons of CO_2e."

NARUC & NASUCA Annual Meetings

No End Seen to State-Federal Tensions

By Rich Heidorn Jr.

BALTIMORE — State-federal tension over electricity policy is likely to continue even after current debates over nuclear and coal subsidies end, speakers told the National Association of Regulatory Utility Commissioners' Annual Meeting last week.

In fact, said former FERC Commissioner **Tony Clark**, "things are probably going to get more tense and more difficult before they get easier."

Clark, an adviser for Wilkinson Barker Knauer who left the commission in September 2016, said there will be pressure for additional state interventions because of the impact of renewables on energy market prices. "Increasingly we see even … relatively new gas units that are stressed in certain markets. Any resource that has higher fixed costs and variable operating costs is going to be challenged in any sort of market where you have price takers with zero variable cost units that are at the margins."

In addition, he said, FERC may begin asserting its authority on power "from the edge of the grid," such as rooftop solar.

"Up until this point, FERC has kind of walled that off and basically … been able to ignore what happens since that's been on the state jurisdiction side of things," he said.

"It's hard to argue that all of these exponentially growing resources at the edge of the grid — in which a sale is by default a sale for resale — [is not] federally jurisdictional activity. To this point it hasn't been that big a deal. It's becoming a very big deal."

Ari Peskoe, of Harvard Law School's Environmental Policy Initiative, said legal challenges to Illinois' and New York's zero-emission credits for nuclear plants "expose a question that courts have not addressed in the 20 years of restructuring: May a state provide an incentive for energy production without intruding on FERC's exclusive jurisdiction over energy sales? Perhaps the state authority over generating facilities means just that — the facilities themselves, and not the energy that they produce," he said.

"There's little doubt that states can enact all sorts of command-and-control regulations over pollution from those facilities. States can issue emission limits or simply prohibit the burning of fossil fuels within their borders. But what about financial regulation of pollution and avoided pollution? And what about state regulation of utility portfolios? Is there some limit on state power that limits states just to those traditional integrated resource plan tools?"

Peskoe filed an amicus brief defending the Illinois ZECs. "Expanding the scope of FERC's exclusive jurisdiction to swallow up ZECs, [renewable energy credits] and other emissions taxes and allowances will disrupt how the industry and how regulators have understood jurisdictional limits," he said.

If the courts accept opponents' reading of the Federal Power Act, "we can expect lawsuits about a range of state programs," he said, adding, "Now concerns about market distortions from ZECs seem pretty quaint in light of [the U.S. Department of Energy's] recent Notice of Proposed Rulemaking."

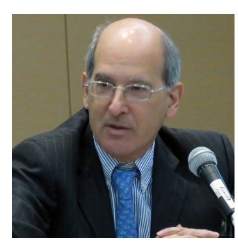
Peskoe said that if ZECs survive the current legal challenges, "existing state policy would be relatively safe from these pre-emption challenges going forward. Then the action turns back to FERC and what FERC is going to do."

He said FERC's May 1-2 technical conference on integrating wholesale markets and state public policies "was a really positive step … so I hope that the DOE NOPR and whatever happens after it doesn't sort of suck the air out of the room and that conversation keeps happening." (See *RTO Markets at Crossroads, Hobbled FERC Ponders Options*.)

Clark said FERC must determine when state actions reach a "tipping point" for its markets. "Whether you think the ZEC is the tipping point or the DOE NOPR is the tipping point, there is a tipping point that FERC has to be concerned about in terms of its maintenance of the integrity of the wholesale market," he said.

"What happens when say … coal-friendly states decide, 'It looks like RECs and ZECs are the way to go. What we need now is a coal energy credit,'" Clark asked.

"We are called the *Environmental* Policy Initiative, so we don't love the idea of coal credits," Peskoe responded. "I'm somewhat comforted by the fact that about 30 states actually enacted RPS and, so far, zero states have enacted coal standards."



Former Commissioner **Marc Spitzer** (2006–2011) was more succinct: "If they're zero-emission coal, go for it!" he joked.

Spitzer, a partner with Steptoe and Johnson, also supported ZECs, saying states are "entitled to deference and forbearance."

From left to right: Tony Clark, Ari Peskoe and Marc Spitzer. | © *RTO Insider*

NARUC & NASUCA Annual Meetings

NARUC Panelists See Need to Define, Price Resiliency

By Rory D. Sweeney

BALTIMORE, Md. — While panelists discussing baseload price supports at the annual meeting of the National Association of Regulatory Utility Commissioners last week didn't find much common ground, they did agree that energy markets should put a price on the attributes the grid needs.

The discussion revolved around the U.S. Department of Energy's Notice of Proposed Rulemaking, which urged FERC to adopt price supports for generators that can maintain a 90-day fuel supply. The proposal has been criticized for ostensibly focusing on coal and nuclear units, but discussion has not focused on what qualities the grid requires to be reliable and resilient.

Steve Herling, PJM's vice president of planning, attempted to narrow it down.

"We probably have the best fuel mix in the industry," he said. "If this is all about fuel mix, this is not PJM that's the problem."

"The proposal on the table is a solution in search of a problem," said Marty Durbin, the executive vice president and chief strategy officer for the American Petroleum Institute, which supports oil and natural gas interests. "We've earned the market share that we have.

"The polar vortex keeps coming out, and I want to grab my red challenge flag and throw it on the floor," Durbin said, referring to arguments that gas-fired units don't have enough fuel security to maintain the reliability of the grid. The severe cold snap in the winter of 2014 created a reliability scare after as much as 22% of PJM's generators were unable to run when dispatched and gas prices spiked.

The NOPR referenced that situation as an example of why larger units with onsite fuel are necessary, even if they are uneconomic.

"Wyoming's interest in the NOPR is really about our customers and our coal, not about coal generation," Wyoming Public Service Commissioner Kara Brighton said.

Define and Value

"We have never viewed the FERC NOPR as a subsidy for coal," said Paul Bailey, the CEO of the American Coalition for Clean Coal Electricity. "We view this as a way to value a resilience attribute."

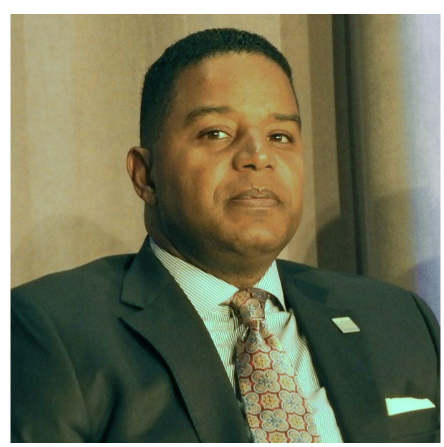
Other panelists agreed.

"We need to decide what's important and put a value on them," Durbin said. "That's really all this is about."

"This has to be solved holistically," Herling said. "Infrastructure alone isn't going to solve the problem. Fuel security alone isn't going to solve the problem. ... Resilience is a rest-of-career conversation."

"Before we conclude that the markets aren't supporting these resources, we should ask the question: 'Do we have the right market rules?'" said **Kathleen Barron**, senior vice president for competitive market policy at Exelon, the nation's largest nuclear operator. "What are the risks that we're facing, both from manmade and natural sources, to those sources of fuel supply? We probably should get some input from [federal departments] that are experts in security ... and have those organizations provide input to the RTOs."

"I tried … in this report to introduce the term 'cyber black-start' as compared to physical black-start. My committee wouldn't let me use that phrase, but basically it is the sort of problem that I'm talking about: How will you get things cleaned up and running well enough, limping along, while you're infected." — M. Granger Morgan, an engineering professor at Carnegie Mellon University, presented the findings and recommendations of his report "Enhancing the Resilience of the Nation's Electricity System." (See *DOE Panel Hears Results of Academies' Resilience Study*.)



"Being part of the Exelon companies, what we've learned is that we're operating across the mid-Atlantic region, and that gives us a scaleability that didn't exist as a BGE standalone. The preparation also involves us making sure that all of our linemen have standard procedures, so that when we're out helping others ... we can communicate with them through an integrated system. ... And we're communicating this with all of our regulators ... so that they know when they see trucks from PEPCO or PECO roll through Baltimore, we're all working safe and integrated." — Calvin Butler Jr., CEO, Baltimore Gas and Electric

NARUC & NASUCA Annual Meetings

Policy Churn, Voting Rules Raise Questions on RTO Governance

By Rich Heidorn Jr.

BALTIMORE — Speaking last week to an audience of consumer advocates, **John P. Hughes**, CEO of the Electricity Consumers Resource Council (ELCON), led off his critique of RTO stakeholder processes with a blunt assessment: "The main takeaway is it can't be fixed."

Other participants who joined Hughes in a panel discussion at the National Association of State Utility Consumer Advocates (NASUCA) annual meeting Wednesday were more optimistic.

Unfortunately, the speakers' opening presentations at the discussion — cheekily titled "20 Years of RTO Meetings and We're Still Not Done?" — swallowed up the entire 70-minute session. As a result, **Denise Foster**, PJM's vice president of state and member services, never got a chance to respond to the critiques.

Room for Improvement

AARP's **Bill Malcolm**, a former MISO manager of state regulatory affairs, opened his presentation by praising RTOs for improving generation dispatch and eliminating rate pancaking.

But he said they should be required to follow open meetings laws and enact ethics reforms, including a ban on revolving-door hiring. He also called for tightening cost controls. "RTOs don't print money," said Malcolm, AARP's senior legislative representative for state advocacy and strategy integration. "It's ratepayer dollars at the end of the day."

He also said RTOs should add ways to better represent residential ratepayers in stakeholder proceedings, including establishing an RTO-funded organization like the Consumer Advocates of PJM States (CAPS).

"Let's make a good thing better," Malcolm said.

Unstable Market Design

Hughes, whose organization represents industrials, said a large manufacturer might have only one or two electricity buyers for national or international operations — making it impossible to monitor the hundreds of RTO stakeholder meetings annually.

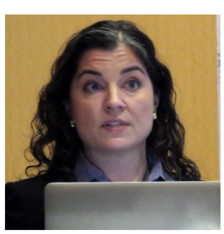
"The market design has never — and may not ever — be stabilized. Therefore, the stakeholder process will forever be the resource hog that it is today," he said, citing capacity markets as an example.

"It is the wrong solution to the problem, caused by not having shortage pricing or surge pricing. And since the capacity market doesn't really work, it's under continual attack for tweaks and fixes that will go on forever unless we come up with a different market design — which I don't think will happen."

Hughes said almost all the proposals that go through the stakeholder process are efforts to increase charges to ratepayers. "The current driver of market design changes — which is [the call for] price formation, including the new [Department of Energy Notice of Proposed Rulemaking] — is very low-cost shale gas. There seems to be a conspiracy to deny consumers the benefit of this resource," he said.

Hughes said ERCOT — which has a board seat reserved for industrial consumers — is the only governance structure his group likes. Industrials' presence on the board means "you gain respect in the whole food chain," he said.

PJM Study



Christina Simeone, director of policy and external affairs for the Kleinman Center for Energy Policy at the University of Pennsylvania, spoke about her May 2017 study on PJM's governance, which asks "Can Reforms Improve Outcomes?"

Among her conclusions: PJM's stakeholder process is very effective on less contentious issues but is less effective on the most contentious issues that are subjected to sector-weighted votes.

Because of affiliate voting, the lower committees are subject to a "huge supply-side bias," she said, citing the now-closed Seasonal Capacity Resources Senior Task Force, where 190 votes were cast by 34 respondents. Just 10 companies can prevent any proposal from passing at the lower level, she said.

But while suppliers can muscle their proposals through the lower committees, she cited a Pennsylvania State University study that found a load-side bias at the upper levels, where End Use Customers and Electric Distributors have formed a tight voting coalition. "What ends up happening is all the proposed solutions are supply-side biased and then they get knocked down by the load-side bias at the higher level. This is a phenomenon I think we're seeing more and more," she said.

She said RTO management has an interest in preventing political backlash over price volatility and blackouts, "so the organization may seek to prevent those things, perhaps at any cost."

She recommended that states have a vote through their governors and that PJM review the makeup of its five sectors, noting the dispersion of stakeholders representing the fastest-growing industry segments: renewable energy (Generation Owners), energy efficiency (Electric Distributors, Transmission Owners and Other Suppliers) and demand response (Other Suppliers).

"In competitive markets, new market entrants are very important. However, they're being lumped in with everybody else and that does a disservice to both the larger firms and the new market entrants because of vote dilution. The larger the sectors get, the less impact any individual firm can have on the process."

She said FERC should require RTOs to re-evaluate their governance process regularly to comply with the "ongoing responsiveness" principle of FERC Order 719.

NARUC & NASUCA Annual Meetings

Overheard

BALTIMORE — More than 1,300 regulators and other stakeholders attended the National Association of Regulatory Utility Commissioners' 129th Annual Meeting and Education Conference at the Hilton Baltimore Inner Harbor, where the theme was "Infrastructure, Innovation and Investment." The National Association of State Utility Consumer Advocates (NASUCA) attracted more than 200 to its annual meeting at the same hotel.

Here's some of what we heard.

Powelson Seeks 'Patience' as New FERC Forms

FERC Commissioner **Robert Powelson** said it will take a while for the commission to move forward on rulemakings that languished during its six months without a quorum.

Powelson and Neil Chatterjee joined Cheryl LaFleur on the commission in August, restoring a quorum. Two other commissioners, Kevin McIntyre and Richard Glick, are waiting to be sworn in after being confirmed by the Senate on Nov. 2.

"It's kind of hard to calibrate around some of these high-level decisions that need to be made. It's critical that people have a little bit of patience as we get back up and running," he told NASUCA.

Powelson said he expects FERC to act on its November 2016 Notice of Proposed Rulemaking on electric storage within the next three months. (See *FERC Rule Would Boost Energy Storage, DER*.)

"We also have a conversation started on the fast-start NOPR," he added. (See *FERC: Let Fast-Start Resources Set Prices*.)

Powelson said he is using the Department of Energy's NOPR for coal and nuclear plants as an "inflection point to see what's working and what's not working in the organized markets. What I know is working hyper-efficiently is wholesale power prices have dropped and that's a darn good thing. … Let's not screw that up."

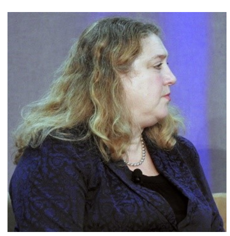
> ***"I don't want to go back to the old days. I really believe in the independence, and protecting the sanctity of that compact for these independent market monitors."***
>
> **FERC Commissioner Robert Powelson**

The commissioner said he also wants to explore "friction" between RTOs and their market monitors, an issue he said was raised by Virginia State Corporation Chairman Mark Christie at a recent conference.

Christie said in an interview later that he was raising a "structural issue that applies across all RTOs." (See *Order 719: FERC Balanced MMU Independence Against RTO Autonomy*.) "What constitutes truly independent market monitoring?" Christie asked. "As the regulator of RTOs, FERC is the appropriate forum to tee up the issue and air it out."

"I don't want to go back to the old days," Powelson said. "I really believe in the independence, and protecting the sanctity of that compact for these independent market monitors. I think they should have the ability to file [with FERC]. And I get a sense that Big Brother RTO wants to say, 'Yeah, you can be seen and heard when it's appropriate.' That's not a good thing in this world of transparency that we live."

Powelson expressed skepticism that Order 1000 has resulted in competitive transmission development, saying it is another subject worthy of a "conversation" to determine "what's working and not working" under the order. "I'm not saying we're going to amend FERC Order 1000, but I think we owe it to ourselves to have that conversation," he said.



Stefanie Brand, director of New Jersey's Rate Counsel, asked Powelson if he was aware of concerns by industrial customers and others about the rising cost of supplemental transmission projects, which are not required by FERC or NERC reliability rules. (See *Report Decries Rising PJM Tx Costs; Seeks Project Transparency*.)

"Yes, it is something we're looking at," Powelson confirmed without elaboration.

Resolutions on Solar Tariffs, Tax Policy OK'd

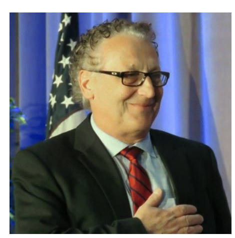
NARUC's Committee on Electricity approved a resolution urging the U.S. Trade Representative "to carefully weigh the harm that could result to energy customers from increasing the costs of solar inputs across the country, and the potential challenges to achieving state renewable energy and greenhouse gas goals that may result from higher solar energy prices." (See *Federal Trade Panel Recommends Solar PV Quotas*.)

It also approved a measure asking Congress not to restrict state regulators' ability to determine how any reduction in corporate income tax rates are addressed in utility rates. The resolution said any reductions in taxes on state-regulated investor-owned utilities "should result in a direct benefit to customers, so long as it is captured in the state ratemaking process."

Betkoski Begins Term as President

NARUC members formally elected Connecticut Public Utilities Regulatory Authority Vice Chair **John W. "Jack" Betkoski III** as its new president for a one-year term. Betkoski has been serving as president since August, when Powelson, a former Pennsylvania regulator, vacated the post to join FERC.

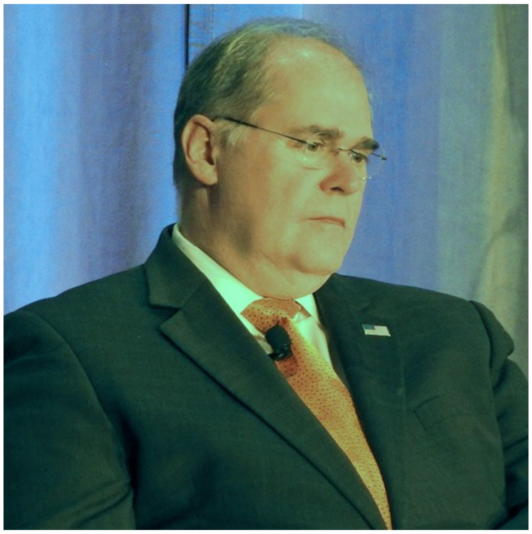
Ellen Nowak, chair of the Wisconsin Public Service Commission, was elected first vice president, and Edward S. Finley Jr., chair of the North Carolina Utilities Commission, as second vice president.



NARUC also named **Andreas D. Thanos**, of the Massachusetts Department of Public Utilities, the winner of the 2017 Terry Barnich Award. The award, which recognizes commissioners and staff who promote international cooperation among utility regulators, is named for the former chairman of the Illinois Commerce Commission, who was killed in 2009 while working for the U.S. State Department in Iraq. Thanos was named in recognition of his work in Europe, Latin America and elsewhere.

— Rich Heidorn Jr. and Rory D. Sweeney

NARUC & NASUCA Annual Meetings



"Most people do have handheld devices, so the movement is for being able to communicate either via text message or email messages to those customers that are likely to be affected or will be affected or have been affected. …The people who are serving your customers are also residents in that community, so the first thing you've got to think of is what's happened to them. ... You have to be ready to bring extra people in to deal with the situation." — Pierce Norton, CEO, OneGas; and board chairman, American Gas Association

"I wish utility customers knew how complex the industries are. Balancing those costs and benefits and risk management is incredibly difficult, and just a greater an understanding of what goes into plugging in your phone or your TV." — Joy Ditto, president and CEO, Utilities Technology Council

"Even where [requests for proposals] didn't anticipate storage, we went and bid hundreds of megawatts of storage at the time really to get some attention to the issue that the processes weren't set up to evaluate it. ... We're finding that especially some of the places that saw bids five years ago, are the ones that are leading the nation in terms of more properly evaluating storage. I think that early exposure ... means that it can be a real solution to more urgent problems when they present themselves." — Praveen Kathpal, vice president, AES Energy Storage

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CAISO NEWS

PG&E Disputes ALJ's Diablo Canyon Recommendation

By Jason Fordney

Diablo Canyon nuclear plant

Pacific Gas and Electric has signaled it will challenge a California administrative law judge's recommendation that the utility be granted only about 10% of the $1.8 billion in recovery it requested for the retirement of the Diablo Canyon nuclear plant in San Luis Obispo County.

The California Public Utilities Commission has scheduled final oral arguments for Nov. 28 over a joint settlement agreement filed by PG&E and interest groups regarding the plant, which the utility has proposed to shut down when its federal operating licenses expire in 2024 and 2025. PUC Administrative Law Judge Peter Allen on Nov. 8 approved the retirement plan but proposed that PG&E be allowed to recover about $190 million of the nearly $1.8 billion in requested rate recovery detailed in the settlement. Allen's decision has no weight until voted upon by the five-member commission.

"While the proposed decision preserves several elements of the joint proposal, it differs in regards to certain key areas, including the employee, community and energy replacement programs," PG&E said in a Nov. 8 statement, adding that it "strongly disagrees with these proposed adjustments."

The utility said it thinks the proposed settlement is appropriate, and "we look forward to advocating for this in our comments back to the CPUC and during final arguments at the end of November."

PG&E first filed the settlement it forged with environmental, labor and anti-nuclear groups in August 2016. It would replace output from the 2,240-MW facility with a portfolio of renewable resources, energy efficiency measures and energy storage. (See *PG&E Files Diablo Canyon Shutdown Request*.)

The utility requested approval to recover $1.3 billion for energy efficiency procurement, $363 million for employee retention and retraining, $85 million to mitigate impacts on the local community, $19 million for license renewal activities, and unspecified canceled capital project costs.

Allen's proposed decision rejected the energy efficiency money and approved $172 million for employee retention and retraining, $19 million for license activities, and a portion of canceled project costs. He recommended that issues related to the procurement of replacement capacity be handled in an integrated resource planning proceeding.

The judge sided with the Office of Ratepayer Advocate (ORA) and Energy Producers and Users Coalition (EPUC), which noted that state policy already requires PG&E to first meet its resource needs through all available energy efficiency resources. PG&E has proposed to increase its approved energy efficiency goals by more than 53% for 2018-2024, which ORA and EPUC indicated would only be possible by lowering PUC's cost-effectiveness threshold.

"ORA and EPUC make a good point — it is not clear that PG&E could actually procure over 50% more energy efficiency than a goal that is already supposed to include all cost-effective energy efficiency (unless PG&E procures energy efficiency that is not cost effective)," Allen said. "There is no reason to approve a $1.3 billion rate increase for a proposal that will most likely either fail to achieve its goal or will achieve a goal not worth reaching."

Allen's Nov. 8 proposed decision also took issue with a settlement provision that would replace the property tax paid to San Luis Obispo County with $85 million in ratepayer money, arguing that PG&E has no obligation to pay the taxes once the facility shuts down and that utility rates should be used for utility — and not government — services.

PG&E has proposed to replace Diablo Canyon with greenhouse gas-free resources in three tranches: 2,000 GWh of energy efficiency; 2,000 GWh of energy efficiency and renewables; and a voluntary 55% renewables commitment from PG&E. The utility said additional resource procurement could be required to replace Diablo Canyon, the two units of which began operating in 1985 and 1986. The plant is used as a system resource and not for local reliability, and its output is exported on the bulk transmission system.

The settlement is supported by the Natural Resources Defense Council, Friends of the Earth, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees and the Alliance for Nuclear Responsibility.

Protests against the settlement were filed by California Large Energy Consumers, Californians for Green Nuclear Power, EPUC, several cities, the Sierra Club, Shell Energy North America, SolarCity, public interest groups and others.

After a 25-day public comment period, the ALJ's proposed decision will be forwarded to the PUC. PG&E has requested that the commission reach a decision on the settlement by the end of the year.

CAISO NEWS

FERC Affirms WestConnect Cost Allocation Ruling

Commission Accepts APS EIM Filing, Reaffirms PG&E Rates

By Jason Fordney

FERC last week upheld a previous ruling covering transmission cost allocation in the WestConnect planning region, adding further explanation of its reasoning after a federal court remanded the issue back to it for more information.

The issue stems from an October 2012 compliance filing that WestConnect utilities submitted in response to FERC Order 1000, the 2011 rule governing regional transmission planning and cost allocation. The group's planning region covers Arizona, California, Colorado, Nevada, New Mexico, South Dakota, Texas and Wyoming.

The utilities' initial compliance filing included a provision stipulating that costs for projects selected in a regional plan would be allocated only to beneficiaries who agreed to participate in those projects. Other WestConnect members participating in the planning process would not be obligated to pay for those projects costs, a measure designed to avoid discouraging nonpublic utility transmission providers from participating in planning.

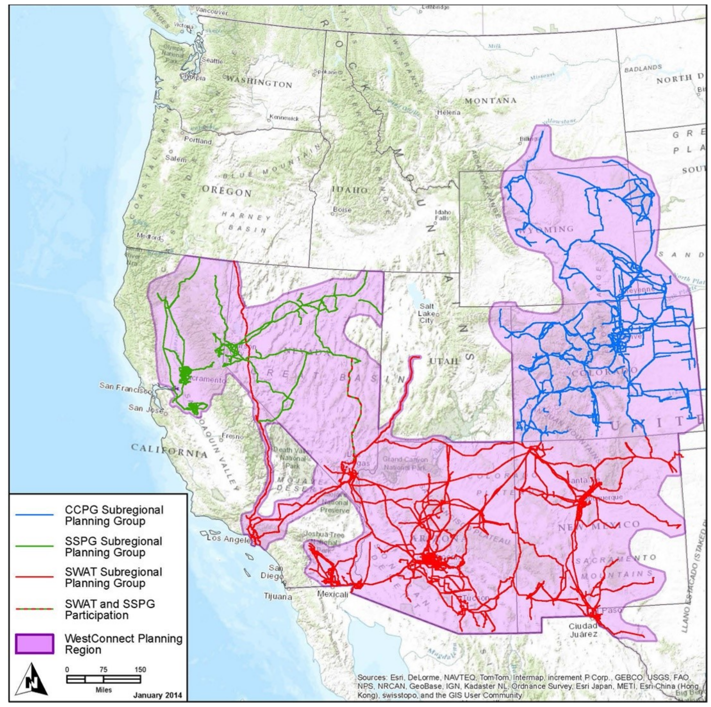
FERC found that WestConnect's "non-binding" process did not comply with Order 1000, which prohibits any planning participants from claiming an exemption from cost allocation merely by asserting they receive no benefits from the resulting transmission infrastructure. The commission noted that the "fundamental driver" of Order 1000 was to minimize "free ridership" within the system.

In response to FERC's rejection, the utilities submitted a second compliance filing containing a new proposal to create separate categories of transmission providers eligible to participate in the WestConnect process: "enrolled" transmission owners subject to the entirety of the Order 1000 process, and "coordinating" TOs — nonpublic utility providers — not subject to regional cost allocation but able to participate in planning. FERC denied a rehearing on that plan and two subsequent proposals that the commission found were similarly deficient in meeting Order 1000 cost allocation requirements. In November 2014 and May 2015, El Paso Electric petitioned the 5th U.S. Circuit Court of Appeals to review the compliance orders.

The 5th Circuit remanded the orders in August 2016 for "additional factual findings" on WestConnect's planning process, saying the commission's mandates regarding the role of nonpublic utility transmission providers were arbitrary and capricious, and that FERC had not shown its orders would not produce unjust rates.

FERC last week declined to change its original finding, saying it "continues to conclude that the approach it ultimately accepted in the compliance orders satisfies Order 1000 while taking into account the uniquely integrated nature of public and nonpublic utility transmission systems in the WestConnect transmission planning region" (ER1375-011, *et al.*).

The commission determined that its original decision "appropriately" considered the "unique characteristics" of the WestConnect region when determining how to address the participation of nonpublic utility transmission providers in the region's planning process. It noted that some public utilities in the region are connected together by transmission wholly or partially owned by nonpublic providers and that regional planning would be "hampered" without the participation of the latter.



WestConnect planning region | *WestConnect*

"We find no basis in the record to conclude that, if presented with [the] choice, any nonpublic utility transmission provider in the WestConnect region would voluntarily choose to enroll and subject themselves to binding cost allocation," the commission said. "Their decision not to enroll would mean that, under this approach, WestConnect would not conduct transmission planning to meet the nonpublic utility transmission providers' transmission needs."

While the outcome of WestConnect's initial approach would comply with Order 1000, it would also "undermine" the order's goals, the commission said.

The WestConnect utilities included Arizona Public Service; Black Hills Power; Basin Electric Power Cooperative; Powder River Electric Cooperative; Black Hills Colorado Electric Utility; Cheyenne Light, Fuel, & Power; El Paso Electric; NV Energy; and Xcel Energy Services on behalf of Public Service Company of Colorado, Public Service Company of New Mexico, Tucson Electric Power and UNS Electric.

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CAISO NEWS

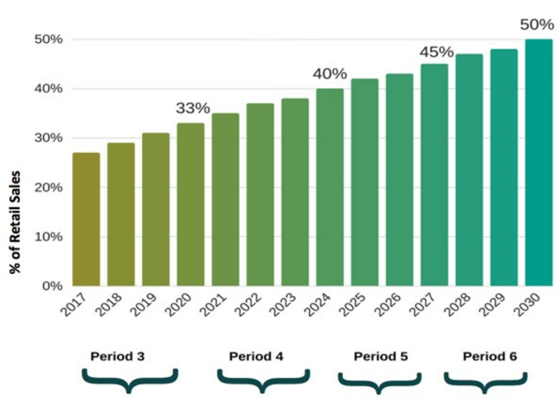
California Utilities Exceeding Renewable Requirements

By Jason Fordney

California electricity suppliers have met the state's 25% renewable generation requirement, in many cases exceeding it substantially, state regulators said.

The state's three large investor-owned utilities have also signed contracts with renewable suppliers necessary to exceed the requirement that they meet 33% of customer energy demand with renewables by 2020, the California Public Utilities Commission said in its Renewables Portfolio Standard report for 2016, issued Nov. 13. The commission is required to submit quarterly and annual reports to the state legislature on the industry's progress in meeting RPS goals.

Retail electric sellers were required to meet 25% of load with RPS-eligible resources by the end of 2016. Pacific Gas and Electric reached about 33% renewables, Southern California Edison about 28% and San Diego Gas & Electric nearly 43%.



RPS compliance periods | *California PUC*

An aggregated forecast projects the utilities will meet the 2030 requirement of 50% by 2020, according to the PUC, which administers the RPS with the California Energy Commission. The PUC's role includes setting policies for implementation, reviewing RPS procurement plans, reviewing IOU contracts and enforcing compliance.

PUC Commissioner Clifford Rechtschaffen said: "Our utilities are exceeding the goals we put in place for them. Costs have continued to decline, and reliability has not been compromised in any way. California's successful program offers lessons for other states interested in advancing clean energy policies."

The program requires IOUs, community choice aggregators, electric service providers and publicly owned/municipal utilities to procure renewables to reduce greenhouse gas emissions, stabilize electricity rates, diversify energy resources and contribute to reliability.

The state's five CCAs and various multijurisdictional utilities report they are compliant with RPS requirements and expect to meet or exceed the 33%-by-2020 requirement.

California's latest RPS requirement of 50% renewables by the end of 2030 was set in SB 350, signed by Gov. Jerry Brown in 2015. The State Legislature is getting heavy pressure from environmental groups to pass a 100% zero-carbon bill that would include nuclear and large hydro in the last 40% of the requirement. Lawmakers are due to take up the legislation in January. (See *CAISO Regionalization, 100% Clean Energy Bills Fizzle*.)

The state's IOUs are currently over-procured for renewables and held no annual solicitations in 2016. But they were required to procure renewables through other programs to meet the future RPS and other state policy goals. These include the Renewable Auction Mechanism, Bioenergy Renewable Auction Mechanism, Renewable Market Adjusting Tariff and Bioenergy Market Adjusting Tariff.

IOUs are also required to comply with "least-cost, best-fit" methodology to ensure the most cost-effective resources are being procured. The PUC plans to reform the methodology.

It said contract prices for solar photovoltaic fell 77% between 2010 and 2016 to an average of $29.17/MWh, and IOU contracts for wind fell by 47% to $50.99/MWh. This is because of the rapid expansion of the market and decreasing technological cost.

The report also lists challenges in meeting RPS requirements, including uncertainty in IOU load forecasts, curtailment of solar due to oversupply at certain periods, stranded costs that could end up with remaining IOU customers as other customers migrate to CCAs, and significant terminations in the Renewable Market Tariff program — a feed-in tariff for small, distributed renewable energy technologies.

FERC Affirms WestConnect Cost Allocation Ruling

Continued from page 9

In other decisions last week, FERC:

- Accepted APS' compliance filing for its participation in the Western Energy Imbalance Market (EIM) operated by CAISO. The utility revised its tariff to address directives by FERC in a Sept. 26 order. The commission accepted APS' proposal to allow external resources to participate in the EIM via dynamic scheduling, subject to a further compliance filing, and the utility's proposal to reflect payments and charges from CAISO in a future rate proceeding (ER16-938).
- Rejected a complaint filed by transmission customers of Pacific Gas and Electric over a proposed rate increase. Complainants said the utility's stated costs were not justified and argued for a rate decrease, but FERC said they had not met the burden for a complaint and did not introduce any new evidence over the rates approved by the commission in a November 2016 settlement. Complaining parties included the Transmission Agency of Northern California; the city of Santa Clara, Calif.; the M-S-R Public Power Agency; the State Water Contractors; the California Public Utilities Commission; the Modesto Irrigation District; and the Sacramento Municipal Utility District (EL17-59).

CAISO NEWS

California Utilities Short on Local RA Capacity

By Jason Fordney

California's utilities are about 2,000 MW short of local resource adequacy (RA) requirements for 2018 according to CAISO, which has asked state regulators to restructure the RA program.

In a Nov. 13 report, the ISO evaluated the 2018 resource adequacy plans of Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. RA requirements are broken down by transmission access charge (TAC) areas, which are based on the service areas of the state's three investor-owned utilities.

"The ISO's evaluation has identified individual [load-serving entity] and collective capacity deficiencies in several local capacity areas in the PG&E, SCE and SDG&E TAC Areas," the ISO said.

Because CAISO evaluates RA for local load pockets as well as the overall system, capacity procurements made through the California Public Utilities Commission RA program don't always align with the reliability needs identified by the ISO. As a result, the ISO at times depends on out-of-market payment schemes to keep fossil-based resources online to support local reliability, a practice that has created tension among market participants and concern at the ISO's Board of Governors. (See Board Decisions Highlight CAISO Market Problems.)

The PUC's RA program requires an LSE's capacity to be available to CAISO when and where needed. There are three types of RA: system resources, local resource adequacy and flexible resources, a category added in 2015 to help manage the changing resource mix.

Deficiencies Abound

The CAISO Tariff allows LSEs and electricity suppliers to address individual capacity deficiencies before the ISO obtains "backstop" procurement. The LSEs are not required to purchase capacity from a specific resource to meet a local need, but can purchase from any resource located locally or with adequate transmission.

"However, to the extent that the aggregate LSE showings do not comprise the right mix of resources that meet the LCR [local capacity requirement] criteria and ISO effectiveness needs, a deficiency may exist that would cause the ISO to procure individual and/or collective backstop capacity," the ISO said.

Such deficiencies did indeed show up in CAISO's findings. The report found an LCR shortfall of 1,072 MW in the PG&E TAC, nearly all of which represents a "collective deficiency" to be addressed by all LSEs within the area. Individual LSE deficiencies represent just 72 MW of the total.

PG&E area shortfalls include a 574 MW need in the South Bay-Moss Landing subarea in the San Francisco Bay Area, and a 422-MW need in the "South of Palermo" section of the Sierra Area.

The SCE area needs an additional 317 MW in the Moorpark portion of the Big Creek-Ventura area, the report shows.

CAISO's 2018 assessment for SCE includes generators that are set to retire in 2020 because of once-through-cooling rules, including a combined 2,076 MW of capacity from NRG Energy's Mandalay and Ormond units. The proposed replacement, NRG's proposed Puente natural-gas fired plant, is strongly opposed by environmental groups and some in the local community.

NRG asked the California Energy Commission to suspend the permit application after two commissioners recommended it be denied. (See NRG Signals Pull-out on Proposed Puente Plant.)

In SDG&E's TAC, the overall deficiency is 560 MW, with individual LSE deficiencies accounting for 475 MW of the total.

Reforms Needed

Separately from the Nov. 13 report, the ISO recently joined with IOUs in asking the PUC to make fundamental changes to the RA program, which is meant to procure sufficient resources to meet reliability needs.

CAISO filed comments Nov. 9 in the PUC's latest RA proceeding saying it agrees that the commission should "establish a separate track of this proceeding to address fundamental resource adequacy issues."

The IOUs want the PUC to simultaneously consider the interplay among the CAISO market structure, the RA construct and state policy goals.

CAISO and others cite the increasing number of reliability-must-run agreements that the ISO has been forced to sign with natural gas units, the most recent being Calpine's Metcalf Energy Center.

CAISO said "the rapid transformation and nature of the resource fleet and other factors are exposing fundamental inadequacies in the current resource adequacy framework."

But the ISO also noted that RMR designations "are a result of these events, not the root cause, and they highlight the need to comprehensively re-examine the resource adequacy program."

Gulf Coast Power Association

Mexican Market Ready to Withstand Political Change, Adviser Says

By Tom Kleckner

Houston GCPA members listen to November's luncheon presentation. | *© RTO Insider*

HOUSTON — It's a sign of the Mexican electricity market's growing strength that at least some industry experts expect little change after the country's presidential elections next year.

The country's constitution limits presidents to single six-year terms. That means every six years, a new president and administration — usually from the Institutional Revolutionary Party (PRI) — is guaranteed to take power, leading to months of transitory uncertainty for the energy sector.

Derek Woodhouse, a partner with CMS Woodhouse Lorente Ludlow, has been advising Mexico's Energy Ministry (SENER) on implementing the wholesale market and drafting its new regulations. He expects 2018 to be different.

"Regardless of who wins the election … they're not going to be able to dramatically change what's being done," Woodhouse said during a Gulf Coast Power Association luncheon last week.

For one, Woodhouse said, market reform was written into Mexico's constitution three years ago. "Second, because the main market rules have been put in place, and can only be changed now by the market itself. It will be hard for them to mess up things," he said.

"I think in many ways, that's why it was assigned this way, so it can support political changes, and political changes will not affect dramatically what is going on."

Continuity or Inertia?

Woodhouse would know. In the late 1990s, he was part of a team drafting the country's initial market reform proposal. When Vicente Fox ended 71 years of PRI rule with his surprise victory in the 2000 election, it put a halt to plans to introduce a competitive market.

"When Fox won the election, nothing happened for more than 12 months, and very little happened for the rest of his administration," Woodhouse said. "That's a political risk of having a new party [in control], because then you cannot have continuity."

Woodhouse said the difference now is the nearly three dozen market rules that have been — or soon will be — put in place since new industry laws and regulations were passed in 2014. They govern everything from financial transmission rights auctions to market registration and outage scheduling. A code of conduct and additional operating guidelines and procedures are among those rules yet to be developed.

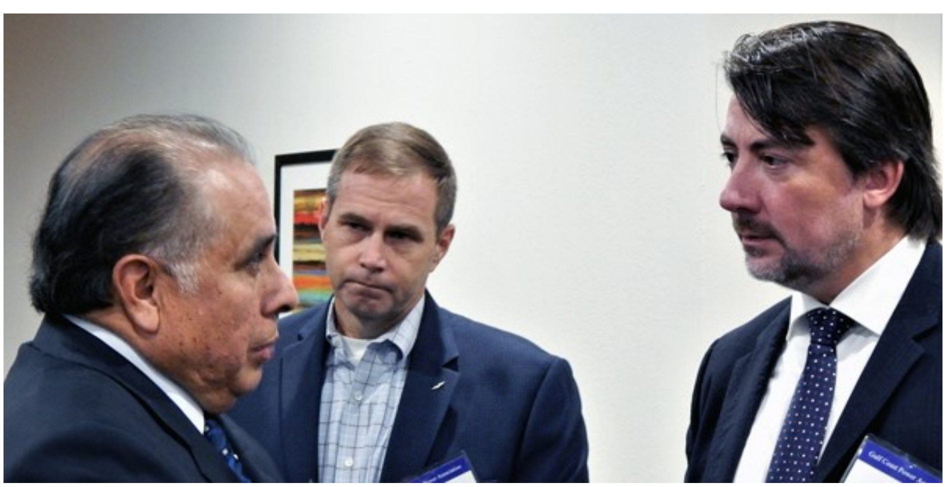
Still, further changes will only be expedited if the PRI manages to replace incumbent President Enrique Pena Nieto with another one of its own, Woodhouse said.

"Then you have continuation. At the end of the administration, people … probably know they're not going to be here, so why take any risk? Why start something you're not going to end? That triggers a year of nobody doing anything," Woodhouse said.

He said the five months that follow a presidential election and the first months of the new administration have been "quite unproductive, particularly when the ruling party changes."

Continuity does reign within the Energy Regulatory Commission (CRE), an independent body. Not so with the state-owned Comision Federal de Electricidad (CFE) that has long controlled Mexico's electricity business. Woodhouse is working with the government to restructure CFE into 16 different companies, including six generation firms, two fuel supply and trading companies, and transmission and distribution businesses.

Woodhouse said inertia during the transition between administrations can still be a



Derek Woodhouse (right) discusses the Mexican market with TMX/NGX's Richard Gutierrez (left) and Continuum Energy's Gary Hillberg. | *© RTO Insider*

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ERCOT NEWS

Texas PUC Briefs

Texas PUC Welcomes Arthur D'Andrea as New Commissioner

Texas PUC Commissioners Brandy Marty Marquez, Chair DeAnn Walker and Arthur D'Andrea.

The Public Utility of Commission of Texas on Friday welcomed Arthur C. D'Andrea, who replaced longtime Commissioner Ken Anderson as its third member.

D'Andrea was appointed by Texas Gov. Greg Abbott on Nov. 14 to a term expiring Sept. 1, 2023. He joins Chair DeAnn Walker, who, like D'Andrea, worked in Abbot's office before joining the commission.

"It seems natural for him to be on the same floor now," Walker said after calling Friday's meeting to order.

Brandy Marty Marquez, now the PUC's longest-tenured commissioner with four years of experience, is the only member to have been appointed by former Gov. Rick Perry. She said it felt "weird" as she sat in Anderson's chair.

"It feels like I'm in a totally different room. Who are all you people?" said Marquez, greeting D'Andrea as the "Brazilian bad boy."

Anderson, whose latest term expired in August, joined the commission in 2008, making him its longest serving member ever.

Marquez shared several thoughts on Anderson with the commission and its audience, teasingly saying he is a "very snazzy dresser" and "likes to rock a winter beard." She also called Anderson "the consummate gentleman, who's not afraid to kick a little hindquarters now and then," and the "ultimate protector of our energy-only market."

Marquez said she had recently read an article that referred to parents as the "original gangsters, because they tell you like it is to your face, and behind your back, they compliment you wildly."

"That's pretty gangster," she said. "Commissioner Anderson never missed an opportunity to compliment his staff, to compliment the staff of the commission, and to compliment the bar that argued before it. He always said that the quality of the folks that came before this commission was his favorite part of the job."

D'Andrea wasted little time in making himself at home, spending nearly 30 minutes questioning parties to a Southwestern Electric Power Co. (SWEPCO) rate case (Docket 46449). The PUC decided to take up the case again at its Dec. 14 meeting over requests by intervenors to be granted additional time to conduct discovery after SWEPCO added late expert testimony.

D'Andrea was an assistant general counsel in the governor's office (2015-2017) and an assistant solicitor general for the state's attorney general (2009-15). He received a bachelor's degree in chemical engineering in 1998 and a law degree from the University of Texas.

PUC to Ask MISO to Create Texas Local Resource Zone

Picking up on an issue Anderson followed for several years, the PUC has requested MISO seek FERC approval to create a separate local resource zone (LRZ) that would "better align the costs and benefits" of market efficiency projects (MEPs) for the portions of Texas within the RTO's footprint.

The commission asked for an effective date no later than Dec. 6, saying it would lead to a "more granular estimation" of transmission projects' costs and benefits. Staff told the PUC that Texas currently pays 18% of the costs while receiving 70% of the benefits, and that a Texas LRZ would still have the state "bearing less of the costs than the benefits."

The action came after Walker attended an Entergy Regional State Committee (ERSC) meeting in place of Anderson, who was the PUC's liaison to MISO.

At their Dec. 7 meeting, MISO's Board of Directors will consider the $129.7 million, 25.5-mile West of the Atchafalaya Basin 500-kV economic project in southeast Texas, which is being submitted as a market efficiency project.

Texas will receive 72.1% of the production cost benefits from the project and be responsible for 17.9% of the costs, while Louisiana will receive 27.7% of the benefits but be responsible for 70% of the costs.

"These cost and benefit impacts have caused discussions within the ERSC members," Walker wrote in a memo to her fellow commissioners. (See *MTEP 17 Advances with Disputed Texas Project*.)

Walker said ERSC members discussed four proposals to address the issue, one of those being a separate LRZ within MISO that would contain only its Texas territory for cost-allocation purposes.

"Commissioner Anderson … spent lot of time on this. This was his preference," Walker said. "After delving into it, I think it's the best answer."

When Entergy joined MISO in 2013, a MISO South sub-region was created that included two LRZs. A third was created in 2015 to incorporate the portions of Mississippi in the MISO footprint.

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ERCOT NEWS

Texas PUC Briefs

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Rulemaking Would Require Periodic Rate Reviews for IOUs

The PUC adopted a proposed rulemaking requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for rate proceedings, as required by the recent Texas Legislature's Senate Bill 735 (Project 47545).

The rulemaking would require each electric utility in ERCOT's footprint to file for a comprehensive rate review within 48 months of its most recent rate order.

The ruling applies to AEP Texas, CenterPoint Energy, Cross Texas Transmission, Electric Transmission Texas, Lone Star Transmission, Oncor, Sharyland Utilities and Sharyland Distribution Services, Texas-New Mexico Power, and Wind Energy Transmission Texas.

In a memo to Marquez and D'Andrea, Walker said she found it "unacceptable" that some non-investor-owned transmission service providers have not had a rate review in more than 20 years. The commissioners agreed with Walker's proposal that schedules for the non-investor-owned transmission providers be considered in a separate docket (Project 46393).

The commission is accepting comments on its proposed rulemaking. It is facing a June 1 deadline under state law to complete the rulemaking.

Commission to Intervene in EDF FERC Complaint

Following an executive session, the commissioners voted to intervene in EDF Renewable Energy's Section 206 complaint against MISO, PJM and SPP (EL18-26).

In its Oct. 30 complaint, EDF asked FERC to order the grid operators to amend their Tariffs and joint operating agreements to provide more information regarding the treatment of "affected systems" — areas that neighbor RTOs hosting new generation.

The complaint has drawn 10 intervenors from a wide range of the industry.

Order 2003 and the RTOs' tariffs and JOAs require the host and neighboring RTOs to "coordinate." But EDF said interconnection customers in MISO, PJM and SPP "have no idea what 'coordination' means because of the lack of detail in the Tariffs and JOAs."

The company said the RTOs should file revisions providing details on the timing of affected systems studies; the base models used in the analyses; cost allocation of generation projects on either side of transmission seams; and whether the studies will use the energy or network resource interconnection service standard.

— Tom Kleckner

Mexican Market Ready to Withstand Political Change, Adviser Says

Continued from page 12

problem, however.

"You need to wait for the new teams to take over their positions, to learn what to do, and start doing it," he said. "And then you will have 12 months when nothing really happens, due to the change in administrations. It's sad because it shouldn't be like that. The new CFE companies have the tools to make changes, and they're simply not using them."

Growing Private Sector Role

SENER is implementing the wholesale market in phases through 2018. It consists of short-term markets (day-ahead, hour-ahead, real-time and ancillary services), medium-term auctions (three-year energy and capacity contracts), long-term auctions, FTR auctions, a capacity balancing market and the 20-year clean energy certificates market (for instruments equivalent to 1 MWh of energy from clean sources).

The market's third long-term auction last week set a new low for average prices at $20.57/MWh, bettering the $33.47/MWh average set in September 2016, according to preliminary results. Mexico is adding 2.56 GW of capacity from 16 new projects, with a total investment of $2.36 billion by players from Canada, China, France, Italy, Japan and Spain.

Among the winners was Consorcio Engie Eolica, a consortium involved in one of the Tres Mesas wind farm phases in Tamaulipas. (See *Energy Wildcatter Hopes to Make His Mark in Emerging Mexican Market*.)

Eventually, SENER will hand over the keys to the market to CRE. (See *Mexico's Power Market Continues to Gain Strength*.)

Woodhouse says there is still a steep learning curve for those used to the old way of doing things. The CFE generation companies can now only sell energy on the spot market or to load-serving entities, not end users.

"We, and other consultants, are devising something that will allow CFE companies to look good politically but still incentivizes the private sector to negotiate joint-venture contracts with them," said Woodhouse, who has focused his career on private-sector participation in infrastructure projects traditionally reserved for the public sector.

"Hiring consultants would lengthen the process by 12 months, so we came up with the idea of allowing CFE companies [and its board of directors], from the top, to sit down and negotiate with private sector participants," he said. "They're not used to doing that. That was perceived as something corrupt under the existing procurement legislation. We are suggesting an alternative because now, legally, they can enter into direct negotiations with the private sector. But they're still very nervous. 'Yeah, but how is it going to look if I sit down and discuss a contract with someone?'"

Woodhouse said the market is just awakening, with many players "just learning how to play the game." Only five companies are operating as qualified suppliers, and doing so with volumes in the 1- to 3-MW range.

"They're testing the waters to see how their software runs, or even develop their software" Woodhouse explained.

Eventually, he said, the transition will end and a proper market will "create new opportunities, competition and, hopefully, bring down electricity prices for all of Mexico."

NECA Power Markets Conference

New England Strives for CASPR Consensus

By Michael Kuser

MARLBOUROUGH, Mass. — ISO-NE is "in the final throes" of a stakeholder process to reach agreement with the New England Power Pool on a two-settlement market construct to integrate state-sponsored renewable energy resources into its wholesale market, CEO **Gordon van Welie** said last week.

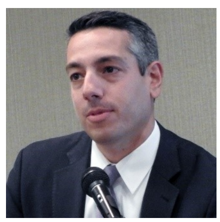
Speaking at the Northeast Energy and Commerce Association's Power Markets Conference on Nov. 14, van Welie said, "We plan to bring this to a vote at the upcoming NEPOOL [Participants Committee] meeting in December and then are going to file it [with FERC] in the December time frame." He referred to the conference as a "quasi NEPOOL meeting," considering that most attendees also participate in the organization's stakeholder meetings.

As part of NEPOOL's Integrating Markets and Public Policy (IMAPP) process begun in 2016, the RTO this year came up with a two-tier market concept called Competitive Auctions with Sponsored Policy Resources (CASPR). (See "CASPR May Exclude New Resources from Substitution Auction," *NEPOOL Markets Committee Briefs*.)

Van Welie said CASPR "is creating the opportunity for existing resources that have capacity obligations and that wish to retire to trade out their obligation with incoming state-sponsored resources in a manner that doesn't affect price formation in the primary auction."

"As much as the states would like to see that their renewable contracts get automatic credit in the Forward Capacity Market, that would run counter to the other objective that we have (aside from reliability), which is to maintain price formation in the capacity market," van Welie said. "CASPR will tend to accelerate the retirements of the marginal units, with significant payout opportunities for some of the older resources that wish to retire."

Seeking Broad Consensus



Sebastian Lombardi, an attorney with Day Pitney who serves as counsel to NEPOOL, said, "We're hoping for consensus because NEPOOL can't have an affirmative institutional position without some broad agreement being reached. Broad agreement has not been reached yet."

The NEPOOL Markets Committee considered a number of modifications to CASPR, he said.

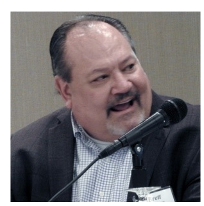
"Although some of those proposals were close to getting broad support, at this stage none of them have reached the requisite support needed for NEPOOL approval, but sometimes three weeks is a lifetime in a stakeholder process," Lombardi said. "Folks have been discussing this for a long time and we're now getting to the endpoint and folks are going to have to make some hard decisions."

Christopher Geissler, an economist at ISO-NE, said that while a number of stakeholder amendments did not pass at the Markets Committee, they could be voted on again by the Participants Committee. For context, he said, stakeholder support in this scenario means a 60% vote by the committee.

"We've made a number of changes to our design on the basis of stakeholder feedback and we continue to elicit and evaluate stakeholder ideas," Geissler said. "However, while stakeholder support is important, we also feel that the design has to meet the objectives that we set out at the beginning of the process, so just because something receives stakeholder support doesn't mean that it's something the ISO will support. It also has to be good market design."

Lombardi added that New England has a unique set of rules and governance arrangements whereby "if NEPOOL were to support something that was different from what the ISO wants to file, more than one proposal could be teed up to FERC on equal legal footing, which would provide FERC some optionality."

Not So Fast



Brett Kruse, vice president of market design for Calpine, gave the NEPOOL talks a 30 to 40% chance of success and described some of the obstacles to reaching an agreement.

For example, the current renewable technology resource exemption is being challenged in federal court, with briefings due Jan. 12, 2018. Kruse said only a couple generators support the CASPR proposal as is, but more would support it if it was modified to protect price formation. He suggested that Calpine's bid shading amendment might win ISO-NE support, particularly as it is already supported by the RTO's internal and independent Market Monitors.

In addition, generators do not support an amendment proposed last week by the New

| © RTO Insider

Continued on page 16

NECA Power Markets Conference

New England Strives for CASPR Consensus

Continued from page 15

England States Committee on Electricity for a 200-MW "backstop" allowing entry of sponsored resources around CASPR in perpetuity.

"I look at CASPR as an interim solution; I think that's the way the ISO has talked about it," Kruse said. "I'm not that positive on the long-term outlook for markets here in New England. Now will that be five years, 10 years? I can't see it getting to 20 years. But even if we get something like this done, I think all that we'll be able to do is slow down the convergence."

Although Calpine is expanding its retail and commercial load-serving business in New England, the company is not looking to develop any new generation other than wind because of Massachusetts' solicitation for thousands of megawatts of clean energy.

"The fundamental stuff shifted because we tend to take the state at their word," Kruse said. "A goal is one thing; a mandate is another; a law is something else. A lot of people I talk to believe there's no way they're going to be able to build that much offshore wind — it's crazy, it will cost way too much money. But when the legislature puts it in a law and the governor signs it, we believe. So we believe all that stuff's going to come in that shifts all the underlying fundamentals."

Regulatory Risk Perceptions

Todd Schatzki, vice president of Analysis Group, said the region's desire to transition to a low-carbon future is driving the market. "But moving from desire to developing market designs and public policies that send effective price signals — we're not there yet. Now we have the dilemma of legislators entering the markets through the back door," he said.

Dan Dolan, president of the New England Power Generators Association, which represents 80% of the region's generating capacity, said regulatory risk is what he hears about most from his members.

"It's the uncertainty of what's next: What is the next large-scale procurement coming from a state?" Dolan said. "It's those issues that then make investing in the tens of billions of dollars in assets that we have here very challenging. ... I challenge you to find another sector of the economy that does not have guaranteed rate recovery and a rate of return investing any multiple close to that in new infrastructure in New England. We are the last major manufacturers in New England."

Darren Matsugu, senior manager for market design and integration at the Independent Electricity System Operator in Ontario, said his ISO has only 8% natural gas-fired generation, compared to nearly 50% in New England. The Canadian province's Legislative Assembly voted in 2003 to phase out coal, and the last coal plant there closed in 2014.

"The majority of our system's installed capacity comes from very low marginal cost resources, whether it's from hydro resources, from nuclear, or from solar and wind," Matsugu said. "Along with the impact of lower natural gas prices, we've seen a significant decrease in the level of our wholesale energy prices. Often at the shoulder periods we fluctuate in the $0 to $10/MWh range."

Beth Garza, director of ERCOT's Independent Market Monitor and vice president at Potomac Economics, provided some perspective for the New Englanders struggling to achieve or accommodate the public policy goals set forth by the region's six states.

"Unlike other areas that have centralized clean energy goals, Texas has not had that, but the markets are responding as if we did," Garza said. "Texas has become a leader in wind generation simply because the zero-cost resource offers investors a good chance to make a profit."

ISO-NE NEWS

Planning Advisory Committee Briefs

New England Economy Sees Slow, Steady Growth

WESTBOROUGH, MA — Boston leads large, northeastern cities in economic growth, outpacing both New York and Philadelphia in payroll employment, Moody's Analytics economist Ed Friedman told the ISO-NE Planning Advisory Committee on Thursday.

According to figures compiled by Moody's from the U.S. Bureau of Labor Statistics, Boston posted better than 2% growth in payroll employment for the three months ending September 2017, compared to approximately 1.7% growth in Philadelphia and less than 1.5% in New York City.

"The job growth in Boston is quite strong and significantly above the U.S. pace, which is around the 1.5% mark," Friedman said.

Friedman characterized New England job creation in the aggregate as "slow but steady" at 1% per year and said that housing price gains in the region are mostly keeping up with the national average of just more than 6% for the year ending in August 2017. Of the six states in the region, only New Hampshire and Massachusetts exceeded the national average; housing prices in Massachusetts, where health care remains a strong economic driver, increased by almost 7%.

Both Connecticut and Vermont lost population in the past two years. Nonetheless, Moody's expects economic growth in the region to continue in 2018 at about 1.3%, with "some deceleration consistent with the demographic challenge" of lost population, Friedman said.

RTO Readies Maine Resource Integration Study

ISO-NE on Thursday presented a draft of its Maine Resource Integration Study to the PAC, its first transmission planning study to employ queue clustering under Tariff revisions approved by FERC in October (ER17-2421). The changes, effective Nov. 1, allow the RTO to consider interconnection requests and upgrade cost allocations in groups rather than individually. (See *FERC Approves ISO-NE Queue Clustering*.)

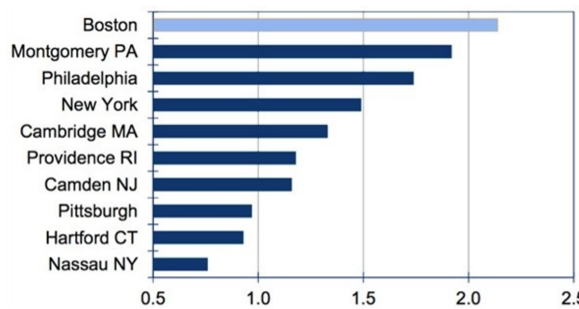
The Northern and Western Maine grid was built to serve the small loads in the area and lacks capacity for the more than 5,800 MW of proposed new resources, mostly wind, that have filed interconnection requests. The 5,800 includes duplicate requests.

The resource integration report will provide the basis for system impact and facilities studies, which will identify the upgrades required for resources that proceed to interconnection and their cost allocations, said Al McBride, ISO-NE director of transmission strategy and services.

Maine 2027 Needs Assessment Moves Forward

The RTO's draft Maine 2027 Needs Assessment study is ready for stakeholder com-

Continued on page 18



Payroll employment: three-month moving average, % change vs. prior year, September 2017 | *Moody's*

Generators' Rehearing Bid on ISO-NE Scarcity Rules Denied

By Rich Heidorn Jr.

FERC last week rejected a request to expand its time frame for relief in a dispute over ISO-NE rules punishing resource withholding (EL16-120-001).

In January 2017, FERC agreed with the New England Power Generators Association (NEPGA) that ISO-NE's peak energy rent (PER) adjustment should be raised. In light of the RTO's new reserve constraint penalty factors, the commission said, the relationship between the compensation that suppliers in scarcity periods and the amount that they must rebate under the PER mechanism was no longer just and reasonable. (See *ISO-NE Scarcity Rules Unfair to Generators, FERC Says*.)

FERC set a refund effective date of Sept. 30, 2016, the date NEPGA filed its complaint.

NEPGA filed a rehearing request asking the commission to apply the revised PER — and any resulting refunds to capacity suppliers — to an Aug. 11, 2016, scarcity event.

FERC on Thursday rejected the request, saying it would impose "an unforeseen and significant increase in costs" to load.

"Such application is inconsistent with the commission's notice requirements under the [Federal Power Act]," FERC said. "We recognize that there is a lag between when the event occurs and when the billing to reflect the PER adjustment takes place; that lag in billing, however, does not satisfy the notice requirements under the FPA."

The January order said the amount of the PER increase would be determined in an evidentiary proceeding if stakeholders were unable to reach a settlement.

On Aug. 31, Settlement Judge H. Peter Young certified an uncontested settlement requiring ISO-NE to increase the daily PER strike price for each hour "by the amounts that actual five-minute reserve shadow prices exceed the pre-December 2014 reserve constraint penalty factors (RCPF) values for 30-minute operating reserves and 10-minute non-spinning reserves ($500/MWh and $850/MWh, respectively)."

The revised strike price will replace the strike price value in hourly PER calculations for Sept. 30, 2016, through May 31, 2018. The settlement has not been approved by the commission.

NEPGA President Dan Dolan and ISO-NE officials could not be reached for comment.

ISO-NE NEWS

Planning Advisory Committee Briefs

Continued from page 17

ment, Jinlin Zhang, ISO-NE lead engineer for transmission planning, told the PAC.

Comments and notifications by proponents of state-sponsored requests for generation should be submitted to pacmatters@iso-ne.com by Dec. 3.

The study identifies reliability-based needs in Maine for the year 2027, considering future load distribution, resource changes in New England based on Forward Capacity Auction 11 results, and 2017 solar and energy efficiency forecasts.

Planners look at reliability over a range of generation patterns and transfer levels, how the study coordinates with the New Hampshire Needs Assessment, and all applicable NERC, Northeast Power Coordinating Council (NPCC) and RTO transmission planning reliability standards.

The completed draft report and intermediate study files will be presented to the PAC in the first quarter of 2018.

RTO Begins Zone Planning for FCA 13

ISO-NE has begun assessing transmission transfer capability, generation retirements and new resources to set capacity zone boundaries ahead of FCA 13 for 2022/23.

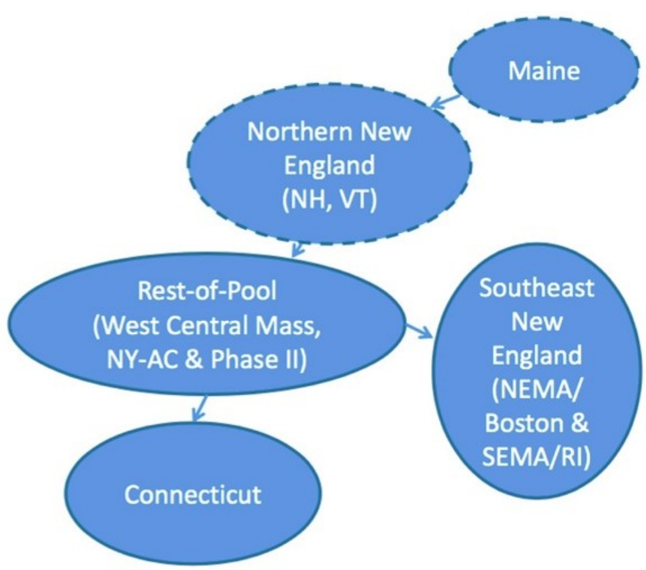
The process includes evaluation of the zones as determined for FCA 12, McBride said.

Each year, the RTO must identify weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Any new boundaries require a filing with FERC, McBride said.

The process of certifying transmission projects begins in October and is coordinated with that month's Regional System Plan (RSP) Project List update to ensure consistency. Transmission owners are required to provide models and contingency definitions. The RTO will determine certifications by January; the list of certified projects will be presented at the January Reliability Committee meeting.

Transmission upgrades identified for Southeast Massachusetts/Rhode Island (SEMA/RI) are not expected to change the boundaries of the area. Planners do not expect such upgrades to be fully certified for FCA 13, nor will transfer limits be updated in time for that auction in 2019.

Any major resource retirements received for FCA 13 will be considered in the zone formation process, McBride said. No major retirements were received for FCA 12.



Potential capacity zone construct for FCA 13 | *ISO-NE*

Time-Sensitive Tx Needs Determination

Pradip Vijayan, ISO-NE senior transmission planning engineer, made a presentation on how the RTO identifies time-sensitive transmission upgrades — those required within three years and thus not subject to the competitive solicitation process.

RTO officials consider when an upgrade will be required after identifying improvements in a needs assessment.

Needs identified from a short-circuit analysis are considered time sensitive unless they are driven by future projects that have an in-service date beyond three years of the completion of the needs assessment.

Steady-state needs observed at off-peak load levels are considered time sensitive. Those seen at peak load levels may or may not be time-sensitive.

The RTO will add a document detailing the process to its Transmission Planning Technical Guide, Vijayan said.

Tx Planning Assumptions Update

ISO-NE is continuing to update the probabilistic methodology and minimum load level used in its transmission planning assumptions, Director of Transmission Planning Brent Oberlin said.

The generator dispatches used in base cases in his report showed the potential for a significant number of generators to be simultaneously unavailable, especially in the Eastern Connecticut (ECT) area. ISO-NE said in October that it would revise the scope of its 2027 needs assessments for ECT, Southwest Connecticut and New Hampshire over stakeholder questions about dispatch modeling assumptions. (See "Tx Planners Rethink 2027 Needs Assessment," *ISO-NE Planning Advisory Committee Briefs: Oct. 18, 2017*.)

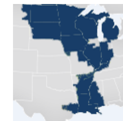
The ECT data showed that up to 488 MW of generation could be unavailable at peak load. The largest generator in the ECT study area is Montville 6 (413 MW), with 13 other generators totaling only 253 MW, which shows that the presence of a single large generator in an area with a low number of smaller generators can skew the results, Oberlin said.

The new methodology solves the issue by recalculating the upper limit of generation outages using the probabilistic method by excluding the large generator for dispatches in which it is assumed in service. By applying this method to ECT, the maximum amount of generation unavailable is limited to 115 MW in cases with Montville 6 in service.

The new methodology lowers the minimum load level to 8,000 MW from 8,500 MW, correcting an error on the handling of Maine mill loads (currently 320 MW) in the evaluations, Oberlin said.

— Michael Kuser

MISO NEWS



FERC Upholds MISO Transfer Limit Policy

By Amanda Durish Cook

FERC on Thursday rejected a rehearing of MISO's subregional flow limits and accepted the RTO's method for calculating the limits.

The commission declined to rehear its December 2016 dismissal of a complaint seeking to overturn the results of MISO's 2016/17 planning year capacity auction. A coalition of transmission customers had argued that subregional transfer constraints where MISO flows must cross SPP transmission are too strict, trapping capacity in MISO South and driving up clearing prices (EL16-112-001, ER17-892). (See *FERC Backs MISO on Transfer Limit, Seeks Details*.)

MISO calculates the transfer limits between its Midwest and South regions by deducting firm reservations from 2,500 MW of available capacity flowing from South to Midwest and 3,000 MW estimated to be available in the opposite direction. The initial limits were set out in a settlement with SPP that became effective in early 2016.

Several MISO stakeholders and the Independent Market Monitor argued that the RTO's subregional constraint calculation is flawed, with a group of transmission-dependent utilities in Wisconsin arguing that the subtraction of all firm transmission service reservations "incorrectly assumes that those holding the reservations will use them all the time, even when it would be counter to their economic interest." The Monitor agreed that the calculation is too conservative.

In its Nov. 16 order, FERC pointed out that while it's possible that not all firm transmission customers will use their service simultaneously, it's also possible they could.

"All parties appear to agree that the regional directional transfer limits established in the settlement agreement are a reasonable starting point for the calculations," FERC wrote. "We agree … MISO's proposal requires it to make two reductions, when applicable, to the regional directional transfer limits: (1) a reduction, based on a feasibility analysis, for reliability purposes; and (2) a reduction by the amount of firm transmission service reservations in the prevailing direction."

Multiple companies submitted alternative proposals for calculating subregional constraints, but FERC declined to examine their fairness.

"There may be more than one just and reasonable methodology that MISO can use to calculate subbegional constraints. We need not analyze whether the various alternative proposals are also just and reasonable," the commission said.

FERC also clarified — at WPPI Energy's request — that its finding regarding the 2016/17 auction should not be construed as "conclusive proof" that MISO's approved methodology will be considered the best course for future capacity auctions.

Monitor Concerned with Cost of Midwest-South Constraint

The order comes as the Monitor is reiterating concerns about the cost of the SPP contract path with respect to make-whole payments.

"We've been coming at MISO with concerns about the RSG [revenue sufficiency guarantee] on the North-South constraint for some time now," Monitor David Patton said.

Patton said the constraint contributed to $3 million in revenue sufficiency guarantee payments in April 2017 alone.

"It's a vexing constraint because it's not a physical constraint; it's an agreement," Patton said during an October Market Subcommittee meeting.

He said the constraint created about $9 million in RSG payments from September through mid-October, with $6 million of that paid to a single company. "These are wasteful costs," he added.

Earlier this year, MISO conducted a study to evaluate the benefits of constructing transmission to link the Midwest and South areas. The RTO concluded that not one of 35 potential projects could pass the 1.25-to-1 benefit-cost criteria based on adjusted production cost benefits. (See "No Tx Coming for North-South Constraint," *MTEP 17 Proposal: 343 New Transmission Projects at $2.6B*.)

MISO to Seek Waiver After FERC Rejects Offer Cap Plan

CARMEL, Ind. — MISO will seek a series of waivers in order to implement wintertime energy offer caps after FERC rejected the grid operator's proposed cap design, RTO officials said.

Staff signaled the move a week after the rejection of MISO's Order 831 compliance filing, which the commission said wrongly prohibited resources from submitting cost-based offers above the $2,000/MWh hard cap. (See *MISO's Plans for Wintertime Offer Caps Stalled by FERC*.)

For the past three winters, FERC has granted MISO a waiver of its $1,000/MWh offer cap. During a Nov. 14 Informational Forum, MISO Senior Director of Systemwide Operations Rob Benbow confirmed the RTO will seek a similar course this winter. (See *MISO Granted Winter Waiver on Offer Cap*.)

The waiver would allow resources to recover verifiable incremental energy costs higher than MISO's existing $1,000/MWh offer cap for the season. That practice was prompted by a 2014 extreme cold snap that sent fuel costs soaring and saw some MISO generators offering at the $1,000/MWh cap, indicating they may have incurred costs in excess of the cap.

Benbow did not disclose what MISO is contemplating to revise its initial Order 831 proposal or when the RTO will attempt another filing. In turning down the plan, FERC said MISO did not describe what factors would be considered when verifying cost-based offers or distributing uplift and was silent on its treatment of external supply offers in excess of the cap.

Rob Benbow | © *RTO Insider*

"Right now, we're reviewing this order," Benbow said. "In the meantime, we have a temporary waiver to put in place. … That waiver is being worked on right now, and we'll get that out shortly."

— Amanda Durish Cook

MISO NEWS

MTEP 17 Advances with Disputed Texas Project

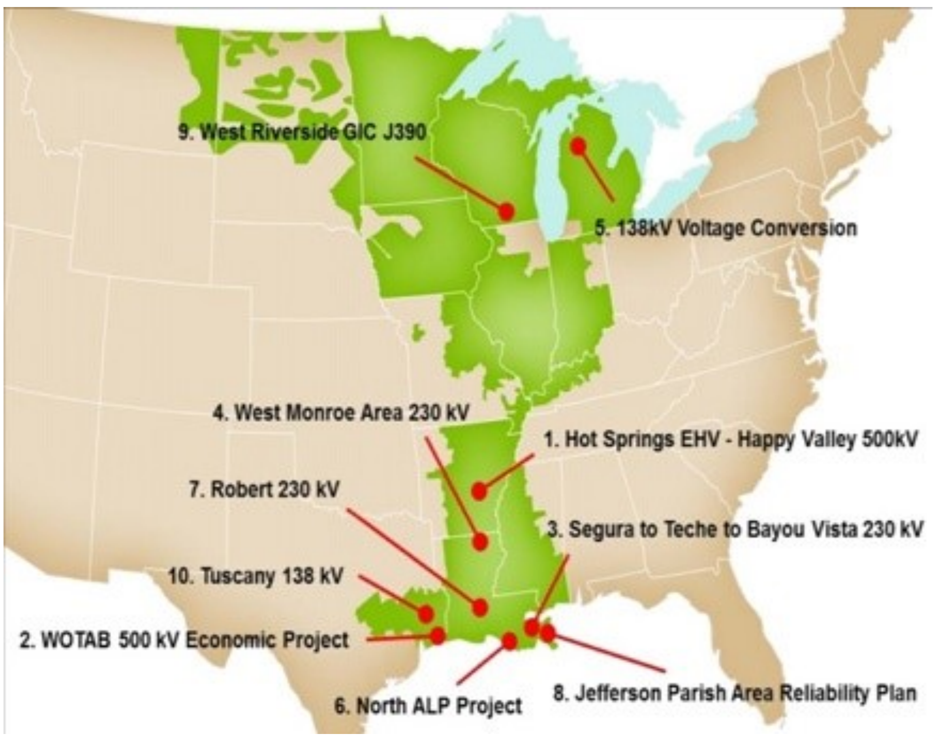
By Amanda Durish Cook

A MISO Board of Directors committee has advanced a $2.7 billion transmission development package that includes 353 new projects — including one divisive line proposed for Texas.

The System Planning Committee of the Board of Directors last week allowed MISO to move ahead in recommending its 2017 Transmission Expansion Plan for full board approval in early December, with RTO staff acknowledging that the plan's only market efficiency project and competitive bidding candidate has drawn stakeholder ire.

MISO Vice President of System Planning Jennifer Curran said the $129.7 million, 500-kV line and substation in southeastern Texas underwent additional vetting to address concerns about the project's costs. The RTO hired an additional consultant who verified its estimate, she said.

"As a result, we're comfortable with the cost estimate for the competitive transmission process," Curran told the committee during a Nov. 16 conference call.



Top 10 MTEP 2017 projects based on cost | *MISO*

MISO's Transmission Owners sector last month submitted an unsuccessful motion asking for a six-month delay of the project — one of the priciest in MTEP 17 — until the RTO addresses late modeling changes and a shifting cost estimate on the project. (See *MISO Sectors Mull Texas Project Delay for MTEP 17*.)

Xcel Energy had questioned the process behind the cost estimate, while Entergy submitted comments expressing concern about MISO overstating the benefits of the project and questioning modeling assumptions used to determine generator commitments in future system planning models.

"We disagree with the comments and continue to recommend that the project go forward," Curran said. She added that the RTO would have risked reliability issues if it granted a delay of the project. The project is meant to alleviate constraints in MISO South's West of the Atchafalaya Basin load pocket area straddling Texas and Louisiana.

Director Todd Raba asked what recourse Xcel and Entergy have available after MISO rebuffed their concerns. Curran said the companies could approach the board with their concerns and can pursue the RTO's dispute resolution process.

MISO South Getting More Attention

Curran said more than half the projects in MTEP 17 are baseline reliability projects, most of which are concentrated in MISO South.

"Some of it is just the general lumpiness of upgrades ... based on when projects need to be undertaken. Some of it is the continued load growth in the South that is not happening in other parts of our footprint," Curran said.

October Brings MISO Lower Prices, Wind Record

CARMEL, Ind. — MISO set an all-time wind output record and experienced lower demand and prices during a relatively cool October, the RTO said last week.

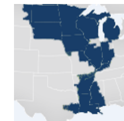
Load peaked for the month at 89 GW on Oct. 9, and averaged 70 GW, 6 GW lower than in September, beginning the "seasonal transition to cooler weather conditions," MISO Senior Director of Systemwide Operations Rob Benbow said during a Nov. 14 Informational Forum meeting.

Energy prices averaged $28/MWh in the day-ahead market and $27/MWh in the real-time market for the month, a 10% decline from September. Natural gas prices lingered around $2.84/MMBtu, lower than September's $2.94/MMBtu average. Real-time make-whole payments fell by more than half, from just more than $13 million to $6.5 million.

Propelled by the windier shoulder season, MISO's wind energy output spiked during the month, setting a new peak wind output record of 14.3 GW on Oct. 30, 0.6 GW higher than the previous record set in December 2016.

Benbow said the increased output was primarily driven by an increase in installed wind capacity throughout 2017. MISO's registered wind capacity currently stands at about 16.8 GW.

— Amanda Durish Cook



MISO Eyes Small Queue Changes, Merchant DC Interconnections

By Amanda Durish Cook

CARMEL, Ind. — MISO will next month submit two filings with FERC to further refine its new generation interconnection process, while a third filing early next year will seek to facilitate connections for merchant HVDC lines, the RTO said last week.

MISO Manager of Resource Interconnection Neil Shah said the two near-term filings — one to limit the amount of time interconnection customers can change their megawatt values and the other to update the interconnection request form — serve as a "clean up" to implement details the RTO missed in its filing to redesign the queue.

The first revision would shorten the period for generation owners to change the capacity volume associated with network resource interconnection service (NRIS), moving the final selection to the second decision point in the queue rather than just before MISO begins an interconnection facilities study.

The second change would update the interconnection request form that prospective generation owners fill out upon entering the queue to include options for external NRIS and MISO's fast-track request option for small generating facilities.

Shah said he did not expect the filings to elicit protests from stakeholders, who offered no public comment on the changes during a Nov. 15 Planning Advisory Committee meeting.

Wind on the Wires' Natalie McIntire said she hoped the filings were as harmless as Shah characterized. "It'd be nice to finally have some queue changes that are uncontested," she joked.

The apparently benign queue changes come as some stakeholders are already calling for a fundamental reconsideration of the interconnection queue not even a year after the RTO rolled out a redesign of the process.

Earlier this month, EDF Renewables asked MISO to consider a two-stage queue instead of the RTO's selected three-stage design, while FERC denied a request to rehear its approval of the new design, which generation developers said should include a fast-tracked queue for vetted projects. (See *EDF Asks MISO to Revisit Queue Overhaul*.)

EDF will return to the Steering Committee in January to make its case for a streamlined queue.

HVDC Interconnection

Another interconnection-related filing in January or February would revise MISO's Tariff to allow merchant HVDC lines to inject energy into the RTO's transmission system at certain points of connection. Under the proposed rules, merchant HVDC would advance through the queue much like other interconnection customers and earn injection rights. However, MISO would draw a distinction between "injection rights" and "interconnection rights." A merchant HVDC owner could only secure injection rights, and its associated generator must also line up in the queue and reference the HVDC injection rights. MISO would then convert the injection rights into interconnection rights for the generator without further queue studies. Only then would the rights be usable to offer energy or capacity into the MISO markets.

In response to a question by Indiana Utility Regulatory Commission adviser Dave Johnston, Shah said there are currently HVDC projects on hold in the queue, most of which are requesting injection rights into MISO.

WOW consultant Rhonda Peters said it's still unclear how MISO will treat a merchant HVDC line wishing to withdraw from the system and inject into another balancing authority.

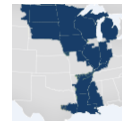
"As of now, these procedures are not supported," Peters said.

Shah said some existing Tariff provisions would allow for withdrawal. "There's some work needed, but it's mostly educational in my mind," he said.

Peters countered that the "thousands of megawatts" that HVDC lines are able to move is "unprecedented" and MISO's current $4,000/MW upfront fee for the definitive planning phase is prohibitively high and will hinder the connection of projects. She asked for MISO to consult with other RTOs about their merchant HVDC interconnect policies.

Shah said he would take those suggestions into consideration and asked stakeholders to provide other input by Dec. 1. More discussion on merchant HVDC interconnection procedures is planned for the December PAC meeting.

MISO NEWS



New Director to Join MISO Board, 2 Keep Seats

By Amanda Durish Cook

CARMEL, Ind. — A former airline executive is slated to become the newest member of MISO's Board of Directors, while two incumbents will retain their seats, the RTO's voting members have decided.

Newcomer Theresa Wise, former chief information officer for Delta Air Lines, will join Baljit "Bal" Dail and Thomas Rainwater to begin three-year terms on the nine-member body beginning Jan. 1.

Theresa Wise | *Delta Air Lines*

Wise has also served as an executive consultant at Amtrak and CIO for Northwest Airlines. She holds a bachelor's in mathematics from St. Olaf College and a master's and Ph.D. in operations research from Cornell University.

"We are pleased to have an executive with Theresa's knowledge and experience join the board. … With Theresa's election and Bal and Tom returning to the board, we are well positioned as a governing body to continue providing steady, strategic guidance as MISO leadership navigates future challenges and opportunities," board Chairman Michael Curran said in a statement.

Dail stood for a fourth term after receiving a waiver of rules limiting directors to three terms. MISO's Nominating Committee granted the exception in June, saying Dail was needed to preserve the board's knowledge about information technology. The decision was not taken lightly, committee members said. (See "Committee Permits Consideration of Extra Term for Dail," *MISO BoD Briefs*.)

Wise replaces current Director Paul Bonavia, who announced this fall that he would not seek re-election for personal reasons. (See *MISO Board Announces Candidates, Hears Budget Review*.)

"Paul's got some things he needs to tend to at home, and that's going to take him away from MISO for the time being," CEO John Bear said during a Nov. 14 Informational Forum. Bear commended Bonavia's contributions over the last three years.

"Director Bonavia served MISO with the utmost commitment to our vision and mission — and we are grateful for his service," Curran said. "He can leave the board knowing that his leadership helped propel the organization in the right direction."

Vote Net Solutions, vendor for MISO's election process, confirmed that 83 online ballots were cast. MISO needed 25% of its 138 voting members to participate to meet its quorum. Electronic voting was open for over a month.

John "Jeb" Bachman, former partner at PricewaterhouseCoopers, and Wolfgang Richter, former CIO at the consulting firm, stood as alternates in the election in the event that any of the candidates failed to garner a majority vote, but neither alternate proved necessary. In MISO board elections, alternates only rotate into the election for a second round of voting if any of the candidates don't receive a majority in the first round.

MISO Defers Retirement Process Changes

By Amanda Durish Cook

CARMEL, Ind. — MISO will delay until next year its proposal to implement a more open-ended approach to its generator retirement process while it looks into possible modeling implications stemming from the change.

MISO adviser Joe Reddoch last week said the RTO will file the plan with FERC in March instead of by the end of the year, giving it time to evaluate whether the more flexible retirement rules will affect its generator availability modeling assumptions used in planning studies.

Reddoch said the new process is "designed to address both temporary and permanent shutdown scenarios," and asked for stakeholder opinions on the plan through Dec. 5.

Under the proposal, MISO would announce retirements and rescind interconnection rights only after a generator fails to return from a 36-month suspension period or if an asset owner announces a retirement date before the three years are up, Reddoch said during a Nov. 15 Planning Advisory Committee meeting. Owners will also no longer be required to supply MISO with an estimated return-to-service date when suspending their units. Suspensions lasting fewer than two months and planned generator outages will not be subject to the new process.

Earlier this year, MISO proposed to reduce its Attachment Y process to a catch-all "economic shutdown" status that no longer recognizes temporary suspensions. The RTO has since dropped that term and tripled the amount of time granted for changing a retirement decision, but it still proposes to combine its separate suspension and retirement procedures into a single process. (See "MISO Moves Toward Singular Attachment Y Status," *MISO PAC Briefs: June 14, 2017*.)

MISO last month received two retirement notices under the existing process, representing more than 1,000 MW of capacity. The RTO typically receives a maximum of four retirement and suspension notices per month, and the combined requests rarely exceed 1,000 MW. MISO has already approved the retirement of 735 MW of capacity for the first five months of 2018. Since 2005, MISO has approved 164 retirement notices and issued 10 system support resource agreements.

Joe Reddoch | *MISO*

NYISO NEWS

Business Issues Committee Briefs

Natural Gas Prices Double, Still Historically Low

RENSSELAER, N.Y. — NYISO year-to-date monthly energy prices averaged $34.89/MWh in October, a 4% increase from a year earlier, Senior Vice President for Market Structures Rana Mukerji told the ISO's Business Issues Committee (BIC) on Wednesday.

Locational-based marginal prices (LBMPs) averaged $28.35/MWh for the month, down 4.1% from September and up 27% from October 2016. The ISO's average daily sendout was 398 GWh/day, compared with 437 GWh/day in September and 391 GWh/day a year earlier.

New York natural gas prices rose nearly 4% in October, averaging $2.36/MMBtu at the Transco Z6 hub. Prices were double those of a year ago, although still "historically low," Mukerji said.

Distillate prices rose 14.9% year on year, with Jet Kerosene Gulf Coast averaging $12.30/MMBtu, down from $13.40 in September. Ultra Low Sulfur No. 2 Diesel NY Harbor averaged $12.86/MMBtu, compared with $12.80 in September.

The ISO's local reliability share was 14 cents/MWh, down 2 cents/MWh from the previous month, while the statewide share remained unchanged at -50 cents/MWh. Total uplift costs were lower than in September.

External Capacity and Imports

Reviewing the Broader Regional Markets report, Mukerji highlighted NYISO's effort to clarify the minimum deliverability requirements for PJM resources seeking to export into the ISO's installed capacity (ICAP) market. He noted that during an October ICAP Working Group meeting, the ISO provided an overview of the current approach to assessing the deliverability of external resources into the New York Control Area for purposes of qualifying eligible capacity within the market.

NYISO is also modifying the documentation requirements for capacity imports across the PJM AC ties, with a planned effective date of May 1, 2018. The process change will require submission of documentation on the day the ICAP Spot Market Auction results are posted to demonstrate that external resources with capacity awards relating to imports across the PJM AC ties have firm transmission service for the month.

The ISO also is considering whether an Atlantic Economics proposal, or an alternate formula-based model, may be viable for calculating locality exchange factors (LEFs). NYISO has engaged General Electric to investigate the viability of potential refinements to the current methodology for determining LEFs.

NRG's Kelli Joseph Elected Vice Chair

The BIC last week elected Kelli Joseph, NRG Energy's director of market and regulatory affairs, to serve as vice chair of the committee for the 2017/18 term.

Joseph advocates on behalf of NRG at NYISO and the New York Public Service Commission and worked at NYISO as a grid operations senior analyst prior to joining NRG in 2014. She attended Houghton College and earned a Ph.D. in political economy at the University of Virginia and an international MBA at the IE Business School in Spain.

BIC Approves Developing New LCR Methodology

The committee also voted for NYISO to continue developing a new methodology to determine locational capacity requirements (LCR), subject to updating the net cost of new entry curve to be used in the ISO's baseline assumptions.

Zachary Stines, associate market design specialist for the ISO, told the BIC that the new optimization methodology results in increased stability as generation changes occur within the system. He said the ISO sought to develop capacity requirements that maintain reliability while minimizing the total cost of capacity at the level of excess condition, i.e., the applicable minimum installed capacity requirement, plus the capacity of the relevant peaking plant.

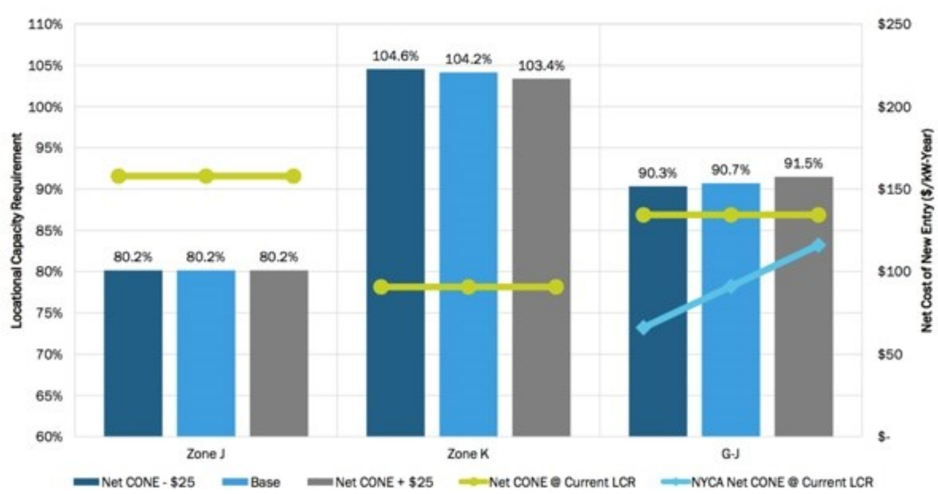
David Clarke of the Long Island Power Authority opposed the proposed methodology, saying it is based on an unrealistically low estimate of net CONE on Long Island.

Mark Younger of Hudson Energy Economics wanted the ISO to commit to refreshing the database with the current net CONE values so that the optimization uses the same CONE as that used in the energy market. Stines said the ISO would do so early in 2018.

Questions on Integrating Public Policy Task Force

NYISO Senior Manager for Market Design Michael DeSocio's progress report from the Integrating Public Policy Task Force (IPPTF) elicited a half-hour of stakeholder dissension over the ISO's definitions of "harmonizing" versus "accommodating" public policy.

Continued on page 24



| NYISO

Downstate NY to Pay 90% of AC Tx Projects

By Rich Heidorn Jr.

FERC on Thursday approved NYISO Tariff revisions ordering downstate residents to pay 90% of the cost of AC transmission projects stemming from public policy needs (ER17-1310-001).

The projects, which include the estimated $1 billion Edic-Pleasant Valley 345-kV line and the $246 million Oakdale-Fraser 345-kV line, are intended to relieve downstate congestion by upgrading the AC transmission systems north and west of New York City.

The cost allocation was proposed by the ISO at the direction of the New York Public Service Commission, which said 75% of the costs should be allocated solely to the downstate load zones that will benefit from the congestion relief, with the remaining 25% allocated regionally based on load-share ratio. "According to the New York commission, this method will allocate approximately 90% of the transmission project's cost to ratepayers in the downstate region, and about 10% to upstate ratepayers," FERC said.

FERC rejected a protest by four State Assembly members, who said the regional allocation of 25% was too low to account for "some of the financial and societal benefits to ratepayers statewide."

The commission said the proposed allocation satisfies Order 1000's requirement that it be "roughly commensurate" with the benefits that the load zones receive, citing a study published by the PSC that found 89.5% of the costs should be allocated to the downstate load zones.

However, the commission added that the ISO's filing "does not prevent the selected transmission developer from submitting its own proposed cost allocation method for the AC transmission upgrades. The Tariff specifically provides that the selected transmission developer may also file, for the commission's approval, an alternate cost allocation method or request that NYISO use the default cost allocation method (i.e., load-share ratio)."

ROE Settlement

In a related order, the commission approved a settlement with New York Transco — affiliates of the New York Transmission Owners, Consolidated Edison of New York, National Grid, Iberdrola USA and Central Hudson Gas & Electric — to decide questions regarding their potential compensation for the projects (ER15-572).

The commission had set the matter for hearing in April 2015. (See *Divided FERC Trims ROE on NY Tx Projects, Orders Hearing*.)

The settlement, which will apply only if NY Transco is selected as the developer, includes a 9.65% base return on equity and a 100-basis-point adder that will apply up to the cost cap, which was defined as the capital cost bid plus an 18% contingency and an inflation factor of 2% per year.

The commission said the settlement, which was unopposed and endorsed by both the New York PSC and FERC staff, "appears to be fair and reasonable and in the public interest."

Cost Containment

FERC did not rule on state regulators' proposed cost-containment mechanism, under which ratepayers would be responsible for 80% of any overruns above the estimated cost of the project and retain 80% of any savings.

The commission said it couldn't rule because the ISO had provided only a description of the risk-sharing proposal without Tariff language. "As such, [the mechanism] is not properly before us," the commission said. "NYISO states that it plans to file Tariff sheets for the 80/20 risk-sharing mechanism after concluding its stakeholder process.

"In regard to implementing the 80/20 risk-sharing mechanism, because the New York commission recognizes that [FERC's] policy on cost recovery allows transmission developers to recover costs that are prudently incurred, it proposes to limit the selected transmission developer's ability to recover costs associated with cost overruns by reducing the allowed return on equity for the transmission project," FERC added.

Selection Process

NYISO received 16 proposed projects from six developers in response to a February 2016 solicitation for solutions to address the transmission congestion. In a January order, the PSC told the ISO it "should proceed to a full evaluation and selection, as appropriate, of the more efficient or cost-effective transmission solution to meet the" public policy transmission need.

NYISO spokesman Michael Jamison said the ISO hopes to release draft results of its analysis by the end of the first quarter of 2018. "Subsequent to that, the NYISO will select the more efficient or cost-effective project. At that time, the NYISO will work out a developer agreement with the chosen party, and that party can initiate actions with the state under the Article 7 transmission siting process."

Business Issues Committee Briefs

Continued from page 23

NYISO and the New York PSC jointly formed the task force in October to create a forum for stakeholders to discuss pricing carbon into the wholesale electricity market along the lines described in a previous Brattle Report. (See *New York Stakeholders Question Carbon Pricing Process*.)

Representing New York City, attorney Kevin Lang of Couch White, expressed concerned about the lack of transmission planning in the task force process, given the amount of offshore wind being sought by the state. Younger agreed, saying that new transmission will be required for the grid to absorb increased amounts of new renewable energy and that nobody should assume the issue has been settled.

"Even if you price carbon, it's unlikely to be high enough to incent renewables development," said NRG's Joseph. "We need to be talking about design changes; that's why we proposed a two-tier market. Not instead of carbon pricing, but while we are at it, look at capacity markets."

In response to a question about whether the task force had a coherent mission, DeSocio said it is focused on fulfilling the goals of New York's Clean Energy Standard.

The IPPTF's next public hearing is scheduled for Nov. 20 in Albany.

— Michael Kuser

NYISO NEWS

FERC Approves NYISO Reliability-Must-Run Plan

By Jason Fordney

FERC last week approved NYISO's tariff revisions to implement a new reliability-must-run program but directed the ISO to make another filing with certain revisions to the initiative (ER16-120, EL15-37).

NYISO submitted a compliance filing Sept. 20 to implement revisions to its RMR proposal, including adding a 365-day notice period for a generator to tell the ISO it plans to retire. FERC had accepted an earlier compliance filing but in April 2016 directed NYISO to make further changes.

The commission rejected a request by the Independent Power Producers of New York and Electric Power Supply Association to shorten the RMR notice period to 270 days. The groups contended that a full year was unnecessarily long. They also made other requests regarding deactivation time and suggested certain incentive payments as part of the program.

In last week's order, FERC directed NYISO to make another filing that clarifies that a generator can propose solutions to a reliability need that are not market-based and can involve generators that are already mothballed or in a forced outage.

The ISO will also require generators to repay revenues that exceed going-forward costs for RMR service and allow units receiving an availability and performance rate (APR) to retain other incentives. FERC's order also asked NYISO to clarify what reliability solutions it will use as its base case to determine reliability needs.

NYISO will also have to "revise the requirement to repay above-market revenues to require repayment of only the above-market revenues that exceed an RMR generator's going-forward costs for RMR service, and to allow RMR generators that accepted an APR to retain their availability and performance incentives."

The ISO must also revise the repayment periods for capital expenditures and above-market revenues to require repayment either within 36 months or twice the duration of the applicable RMR agreement, whichever is shorter.

NYISO must make an additional compliance filing with further revisions by Dec. 16.

PJM NEWS

Rule Changes Could Spur $1.4B Jump in PJM Market Costs

By Rory D. Sweeney

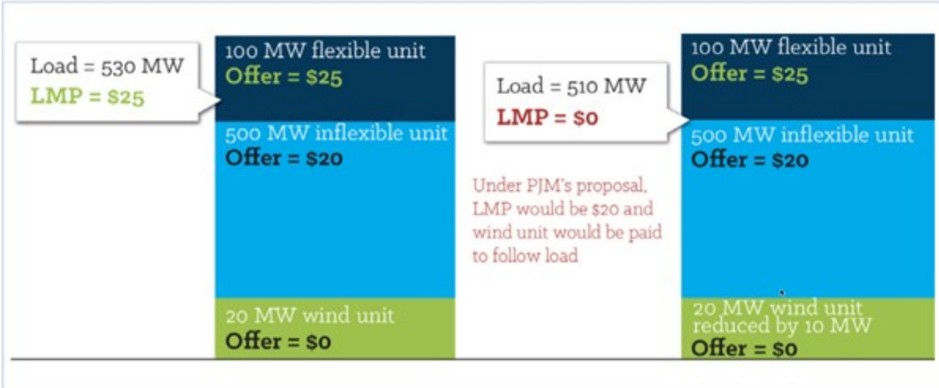
PJM on Wednesday released a proposal for revising price formation rules in its energy markets, teeing up stakeholder deliberation on changes that staff estimate could increase market costs by as much as $1.4 billion.

The two-part plan focuses on reducing out-of-market payments and changing shortage pricing to "accurately reflect the value of energy and reserves during reserve shortages." PJM expects to present the plan to members through a problem statement and issue charge proposed at a Dec. 7 Markets and Reliability Committee meeting. It hopes stakeholders will approve a motion to examine the proposal through the stakeholder process at a second MRC meeting two weeks later.

"Getting prices right is of growing importance, anticipating a continued increase in the penetration of intermittent resources," the report says.

LMP Changes

PJM plans to reduce out-of-market payments, such as uplift, by allowing inflexible units — which can't change their output



An example presented by PJM highlights how its current LMP-calculation method fails to represent true incremental cost. When a flexible unit is on the margin, the LMP is its offer price, but when it is an inflexible unit, the LMP drops to the next flexible unit's offer. The inflexible unit receives uplift as an out-of-market payment to compensate for its costs. PJM's proposal would set LMP at the inflexible unit's offer and pay flexible units lower in the stack to follow the reduction in load. | *PJM*

incrementally — to set LMPs and paying flexible units to better follow load changes.

Speaking during a media briefing Wednesday, PJM's Stu Bresler said that when the RTO implemented LMP, it knowingly included several "simplifying assumptions" that the algorithm wouldn't consider units' fixed costs in the market optimization or allow inflexible units to set prices. The assumptions "served very well," but some of the "downsides ... were masked ... often enough" by flexible resources on the margin and setting prices with higher costs than inflexible units, he said.

"In the past, higher-cost flexible units set price often enough to ensure that all needed resources could earn sufficient revenues in the energy market, when combined with capacity revenues, to drive efficient resource investments," the report says.

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FERC OKs Cost Allocation of PJM Transmission Projects

By Rory D. Sweeney

FERC last week approved cost responsibility assignments for 39 baseline upgrades recently added to PJM's Regional Transmission Expansion Plan (ER17-2362).

The allocations were filed on Aug. 25. Thirty-five projects will be allocated to the transmission zone in which they are located, including five projects of less than $5 million each. Two projects will address Form 715 local planning criteria, and 28 involve circuit breakers and associated equipment. The remaining four projects are "lower voltage facilities" that are allocated based on the solution-based distribution factor (DFAX) method.

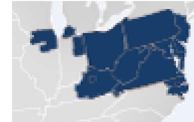
Old Dominion Electric Cooperative challenged two of the DFAX allocations, saying it was unable to replicate PJM's analysis. It asked the commission to direct PJM to provide the detailed information "for the sake of transparency" and to determine whether the upgrades are appropriately allocated entirely to the American Electric Power zone. ODEC questioned PJM's 100% allocation of another project to the American Transmission Systems Inc. zone, arguing that the results of the DFAX analysis produce a 1.32% allocation to ATSI.

FERC accepted PJM's defense of its allocations. The RTO said because only ATSI had a DFAX percentage greater than 1% for project b2898 — reconductoring the Beaver-Black River 138-kV line — that zone was assigned the entire cost of the $20 million project.

PJM said it used "an appropriate substitute proxy" for the baseline projects, reactive power upgrades that can't be addressed by DFAX analysis, which measures over transmission lines or transformers. PJM developed an "interface comprised of the lines and transformers that surround the entire AEP system," a localization method PJM often uses "because the majority of reactive power upgrades are intended to provide local voltage support."

ODEC has also asked the D.C. Circuit Court of Appeals to overturn FERC's policy of allocating all costs from Form 715 projects to the zone of the transmission owner whose criteria triggered the upgrades. ODEC said the cost allocation for the two Form 715 projects should be subject to the outcome of its challenge.

PJM NEWS



Rule Changes Could Spur $1.4B Jump in PJM Market Costs

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"Today, the continuing penetration of zero-marginal-cost resources, declining natural gas prices, greater generator efficiency and reduced generator margins resulting from low energy prices have resulted in a generation mix that is differentiated less by cost and more by physical operational attributes."

Allowing inflexible units to set LMPs and incentivizing flexibility will reduce out-of-market uplift payments and increase the value of flexible units with higher LMPs and flexibility compensation, PJM argues. The extended LMP method, which PJM had told FERC it was "actively exploring," would bifurcate its security-constrained economic dispatch into separate dispatch and pricing runs, as is already done in MISO, ISO-NE and NYISO.

Shortage Pricing

To address shortage pricing, PJM proposes to create a 30-minute operating-reserve product to supplement its current 10-minute reserves and to revise its operating reserve demand curve to more accurately value granular amounts of reserves.

"Improved shortage pricing would substantially enhance market performance," the report said, through incenting demand response and distributed generation "when it is most needed," reducing the "'missing money' problem" that creates generators' reliance on capacity market revenues and providing better signals for transmission investment.

"PJM believes that it is critical that … the shortage-pricing mechanism be reviewed and enhanced," the report said.

Costs

Bresler noted that other grid operators, including MISO and ISO-NE, have already implemented portions of these proposals. He said either element would be "beneficial," but that "we think the maximum benefit would be achieved by implementing both."

The changes would affect both the real-time and day-ahead markets and come at a cost. PJM estimated the energy market changes will likely reduce capacity market costs but still increase overall costs between 2 and 5%, or between $440 million and $1.4 billion, annually.

Bresler said it isn't possible to determine how the proposals would interact with any decision FERC makes on the coal and nuclear price supports suggested by the U.S. Department of Energy or if they would create any instances of double compensation.

"It's very difficult to answer that question in the hypothetical," he said.

Timing

PJM included the proposal in its comments to FERC on the DOE request, arguing that the commission should ignore the department's ideas and instead give the RTO a deadline to present for approval its own solution. PJM had previously floated its proposal at a FERC technical conference on price formation. Members have criticized the RTO's actions as attempting to bypass its stakeholder process.

Bresler said PJM is "very much looking to engage our stakeholder process with the proposal" but declined to rule out filing the revisions unilaterally if they don't receive stakeholder endorsement.

"It's too soon to answer that question," he said. "We did suggest to FERC that putting some time bounds around that discussion and … requiring something back from PJM by some date in 2018 would be beneficial, and I think we'll probably suggest [to stakeholders] … that we get in front of FERC [for approval] sometime in the fall of 2018."

PJM included in its proposal the same letter of endorsement from Harvard economist William Hogan that it submitted with its FERC filing, but the RTO referenced none of the criticism that accompanied the proposal. (See NOPR Reply Comments Bring More Criticism of PJM Proposal.)

PJM NEWS

PJM Stakeholders Split on Request to OK MOPR Compromise

By Rory D. Sweeney

An appellate court ruling remanding back to FERC its 2013 order on PJM's minimum offer price rule (MOPR) has created disagreement among stakeholders about how to move forward.

PJM requested in October that FERC approve its initial 2012 filing on the issue (ER13-535). The RTO had submitted a "hard-fought compromise package" that included two new categorical exemptions to the rule and eliminated a unit-specific one. FERC rejected the initial proposal but said it would approve it if PJM retained the unit-specific exemption and reduced a proposed three-year imposition of the MOPR on affected units to the existing one-year mitigation.

FERC approved PJM's amended filing, but several stakeholders challenged the action and the D.C. Circuit Court of Appeals ruled in July that FERC overstepped its legal authority in telling the RTO what it would accept. (See *PJM MOPR Order Reversed; FERC Overstepped, Court Says*.)

PJM asked FERC to, on remand, "simply accept PJM's original Section 205 proposal, unchanged, as just and reasonable."

The commission's requirements on the unit-specific exemption and mitigation period "have had no practical impact … on the

PSEG's Sewaren 7 natural gas generator is expected to go into operation in summer 2018. | *PSEG*

auction results in the five annual auctions conducted since the commission's initial order in this case," PJM said in its Oct. 23 request.

FERC's concern was "to catch possible future competitive offers that might fall through the cracks theoretically left by the two categorical exemptions," PJM said, but five Base Residual Auctions and nine Incremental Auctions have occurred since then with no unit-specific offers submitted.

"We now know that those cracks, if they exist at all, are quite narrow," PJM said. The commission can conclude that its "concern" about competitive offers slipping through "was overstated."

Stakeholders were split on their opinions of PJM's request. The Independent Market Monitor, NRG Energy and Public Service Enterprise Group argued that FERC had already rejected the RTO's 2012 filing. Several generators said the filing should be approved but with a requirement that PJM address deficiencies in its MOPR within 90 days.

American Municipal Power and Old Dominion Electric Cooperative supported PJM's plan, with ODEC arguing that the new self-supply and competitive-entry exemptions "must be maintained."

"Otherwise, [load-serving entities] like ODEC face the unreasonable prospect of their loads paying twice for capacity, once through the investment in resources (owned or purchased bilaterally outside of the [Reliability Pricing Model] construct), and then a second time when those resources do not clear in the RPM auctions because they are unreasonably subject to the MOPR," ODEC said.

FERC "upset the balance that had been struck by conditioning acceptance" on retaining the unit-specific exemption, it said.

"The commission's authority to issue an order in the form PJM recommends is not in question," AMP said. "That PJM's stakeholders overwhelmingly supported the competitive-entry exemption and the self-supply exemption should weigh heavily in the commission's consideration of how to proceed on remand."

The PJM Power Providers Group (P3) said it

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AEP Base ROE Complaints Ordered to Settlement

By Rory D. Sweeney and Tom Kleckner

FERC said last week it didn't have enough information to decide on complaints that American Electric Power affiliates are raking in unreasonable returns for transmission projects in PJM and SPP, instead establishing hearing and settlement judge procedures.

In PJM, American Municipal Power, Blue Ridge Power Agency, Craig-Botetourt Electric Cooperative, Indiana Michigan Municipal Distributors Association, Indiana Municipal Power Agency, Old Dominion Electric Cooperative and Wabash Valley Power Association filed complaints that AEP's current 10.99% base return on equity is excessive. They requested a base ROE no higher than 8.32% and asked for refunds with interest. The change would save them \$142 million annually in transmission costs, they said (EL17-13).

The complainants hired a consultant to develop a peer-group analysis that included 25 utilities similar to AEP. That analysis found a "zone of reasonableness" of between 5.62 and 9.46% and that the median of the values, 8.32%, was more appropriate than the midpoint.

Multiple state agencies intervened to support the complaint, including the Indiana Office of Utility Consumer Counsel, the Office of the Ohio Consumers' Counsel, the Virginia Division of Consumer Counsel, the Virginia State Corporation Commission and the Indiana Utility Regulatory Commission.

An *ad hoc* group of large commercial and industrial end-use customers also commissioned an analysis, which found an appropriate zone between 5.64 and 9.44%, recommending a base ROE of 8.22%.

AEP responded with its own analysis that found an appropriate zone between 6.41 and 11.71% and that using the midpoint of the upper half of the range, rather than the median, was consistent with FERC rulings.

FERC found the complaint compelling enough to explore further and called AEP's argument that the current rate falls within

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PJM NEWS

PJM Stakeholders Split on Request to OK MOPR Compromise

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supported the RTO's request "in the interest of market certainty" and noted that other dockets exist or likely will come before FERC on the topic "to address broader issues."

Several P3 members, including Calpine, Congentrix Energy Power Management, Dynegy and Eastern Generation, agreed with the group's comments but voiced concern about "deficiencies with [PJM's] MOPR process" and argued that FERC should give the RTO 90 days to address them.

"Recognizing that threats may exist to the efficient operation of PJM's wholesale markets is an understatement, to say the least," the generators said, noting the zero-emission credits for nuclear generation in Illinois and proposals for similar subsidies in Ohio, Pennsylvania and New Jersey.

"PJM must have in place an effective MOPR, applicable to both new and existing resources, to combat the very real threat of these state actions. It is incumbent on the commission to take decisive action on the issue of state-subsidized existing units by extending the MOPR to those units. Continued failure to do so is an abdication of the commission's duties and responsibilities."

PJM had acknowledged in its filing that its finding about unit-specific exemptions "does not rule out the possibility of future low-price competitive offers that do not qualify for the categorical exemptions" and that "that the nature of the potential threats to the efficient operation of its wholesale markets may have evolved since 2012, and accordingly, prospective changes to its MOPR, or its Tariff more generally, may be warranted — but not in this proceeding. PJM has an ongoing stakeholder senior task force considering such issues."

The Monitor argued that FERC was correct to deny PJM's original filing and the court's order didn't vacate that decision.

"The commission's determination that the MOPR was not just and reasonable without an exception for unit-specific cost review was logical," the Monitor said. "The motion should be denied for the same reasons that the commission denied it initially."

NRG and PSEG agreed that the court decision required PJM to return to its original MOPR rule, but split on what other mitigations are necessary. NRG said PJM should just move on with the original rule without retroactively examining the auctions since it was replaced. PSEG suggested a method to recreate the auctions and compensate affected participants.

PJM had argued that because all resources that sought a MOPR exemption pursued categorical exemptions rather than unit-specific ones, the auctions had not been impacted.

"NRG sees something very different: clear evidence that PJM's proposed MOPR is toothless and does nothing to prevent uneconomic entry," NRG said in its filing. "New entrants are making an already over-supplied market even more over-supplied — and are being totally exempted from any review to ensure that their low bids are economically justified. … In order to have a meaningful MOPR that protects the market from artificially low prices, there simply cannot be categorical exemptions so broad that any new generator could drive a truck through them."

PSEG argued the issue is whether the categorical exemptions impacted auction prices differently than how the pre-existing unit-specific one alone would have. PJM should recreate the auctions using commission-approved proxy values for units "inappropriately granted one of the two categorical exemptions to establish the 'but for' auction price," PSEG said.

Any "underpayments" that result would be payable to affected generators by zone; "however, the new entrants that relied upon the no-longer-available MOPR exemptions for a particular auction year would not be eligible for any additional amounts."

SPP NEWS

SPP to Modify Service Agreements with KMEA, Sunflower

FERC last week accepted network transmission service agreements between SPP and Kansas Municipal Energy Agency (KMEA) and Sunflower Electric Power, pending modifications to address the inconsistent treatment of a generation resource (ER17-889).

The commission directed SPP to make a compliance filing within 30 days to resolve a modeling discrepancy in the power-flow analysis, which failed to account for a 9-MW gas turbine (Garden City 2) at KMEA's Jameson Energy Center in Garden City, Kan.

SPP agreed to file revisions to KMEA's service agreement to reflect the additional network resource, with an effective date of March 1, 2017, and to remove a reference to the unit that imposes revenue crediting requirements.

The RTO filed with FERC in January service agreements between it and KMEA as a network customer, and between it and KMEA and Sunflower as a network customer and host transmission owner, respectively. Commission staff tentatively accepted the agreements in March while FERC lacked a quorum.

Sunflower and its Mid-Kansas Electric owner, which also includes five co-ops and a not-for-profit electric company, intervened to point out the initial service agreement with KMEA excluded Garden City 2 but required the unit to pay revenue credits as a network resource. They requested FERC require SPP to remove the unit from the revenue credit payment or add Garden City 2 as a network resource.

SPP acknowledged its mistake and said it performed an additional analysis using updated model information, reposting the results in an aggregate transmission service study in February. It confirmed network service for KMEA used Garden City 2 as a designated network resource, effective March 1.

— Tom Kleckner

FERC Accepts SPP's 'Instantaneous Load Capacity' Term

FERC on Thursday accepted SPP Tariff revisions replacing the defined terms "headroom" and "floor-room" with "instantaneous load capacity," effective June 27, 2017 (ER17-1482).

The commission said the changes "more accurately" describe the purpose, scope and functionality of the ramp capacity requirements the RTO needs in order to manage instantaneous load changes that occur during each operating interval.

Westar Energy and Golden Spread Electric Cooperative protested the revisions.

Westar said SPP failed to provide any specific insight on how it accounts for the differences caused by the operational uncertainties, such as generation deviations, load forecast errors, net schedule interchange deviations and erroneous forecasts for intermittent generators.

Golden Spread argued SPP's addition of the term "operator input" to its reliability unit commitment (RUC) determinations should only apply to extraordinary circumstances. The co-op said instantaneous load capacity should generally be procured by SPP through normal competitive offers based on forecasts.

FERC countered that a degree of operator discretion, "not limitless and consistent with SPP's existing processes, is inherent in reliability commitment processes." It dismissed Golden Spread's and Westar's remaining comments as being beyond the proceeding's scope.

The commission did agree with Golden Spread, however, that it had raised issues SPP should consider exploring through its stakeholder process.

— Tom Kleckner

AEP Base ROE Complaints Ordered to Settlement

Continued from page 28

the reasonable zone "unpersuasive."

"The commission has repeatedly rejected the assertion that every ROE within the zone of reasonableness must be treated as an equally just and reasonable ROE," the order said, setting a refund effective date of Oct. 27, 2016.

SPP Complaint

FERC also established identical procedures for East Texas Electric Cooperative (ETEC) in its complaint against AEP subsidiaries Public Service Company of Oklahoma (PSO), Southwestern Electric Power Co. (SWEPCO), AEP Oklahoma Transmission and AEP Southwestern Transmission, setting a refund effective date of June 5, 2017 (EL17-76).

The cooperative in June asked the commission to reduce the companies' 10.7% base ROE to 8.36% within SPP's AEP West pricing zone. PSO and SWEPCO's current base ROE derives from a transmission formula rate settlement agreement filed Feb. 23, 2009.

ETEC contends the base ROE is no longer just and reasonable and that its ratepayers are currently overcompensating the AEP West companies by $36.6 million annually.

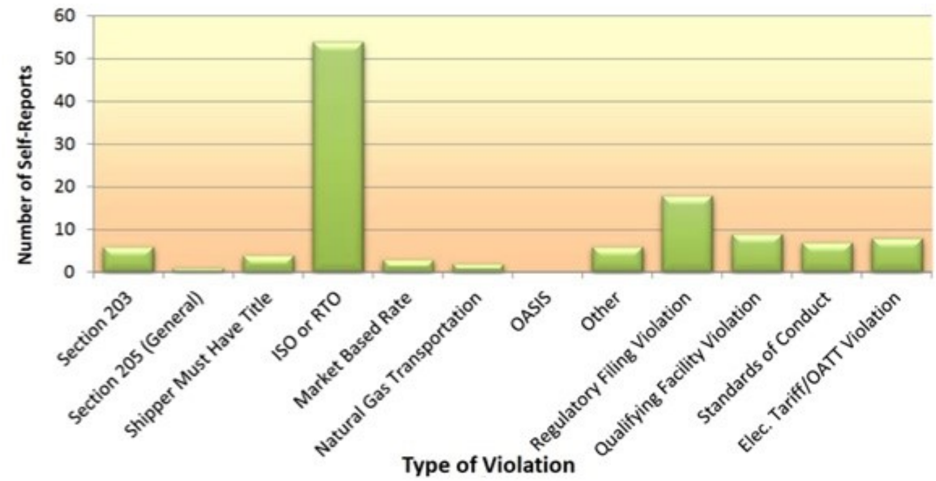
The companies countered that the 9.53% upper end of an ETEC consultant's zone of reasonableness falls more than 100 and 80 basis points below the ROE that FERC previously approved for ISO-NE and MISO, respectively.

The commission said it was "unpersuaded" by the argument, saying "the relief [ETEC] seeks here is an ROE that falls well below the current ROE, based on different facts, risks, proxy companies and time periods" than those in previous decisions.

FERC News

Investigations up Sharply in FY 2017, FERC Report Shows

By Michael Brooks



Self-reports closed in FY 2017 by type of violation | *FERC*

FERC's Office of Enforcement opened 27 investigations in fiscal year 2017, 10 more than the year before, according to its 11th annual report released last week.

The report includes for the first time examples of surveillance inquiries that did not lead to investigations.

In a presentation to the commission Thursday, Enforcement staff said the brief summaries of several instances in which the office's Division of Analytics and Surveillance (DAS) contacted market participants about potential violations were included in the report in response to requests by several regulated entities. They are similar to the examples the Division of Investigations (DOI) has provided on investigations closed without action in past reports. (See *Market Manipulation Cases Dominate FERC Enforcement*.)

"OE anticipates that regulated entities can leverage the example surveillance inquiries to achieve a better understanding of when and why DAS makes inquiry calls, the principles and evaluations used by DAS in making a determination to refer an inquiry to DOI and transactional behavioral patterns that were not deemed by DAS to be problematic or potential violations," Enforcement's John Miller told the commission.

The report masks the identities of the market participants and the markets in which the incidences occur. In one example, DAS flagged large, loss-making increment offers (INCs) at an RTO hub made by a market participant who held a leveraged financial transmission rights path sourced at the hub.

"The market participant explained that the observed INCs covered a period of a planned outage, and that the virtual position shifted a non-leveraged real-time position to the day-ahead market where the market participant hedged commodity risk," the report said. "After verifying the relevant information, the inquiry was closed with no referral to DOI."

DAS' computerized triggers produced more than 300,000 alerts on RTO and bilateral trades, only 31 of which resulted in inquiries. Of those, four resulted in referrals to DOI.

The report also included examples of and statistics on violations that were self-reported. The Office of Enforcement received 80 self-reports last fiscal year, most of which were made by RTOs/ISOs. Most of these were minor violations resulting from human or software error. The examples were included to "emphasize the importance of self-reporting by providing credit that can significantly mitigate penalties if a self-report was made," the report said. "Staff continues to encourage the submission of self-reports, and views self-reports as showing a company's commitment to compliance."

Of the 27 investigations opened last year, 15 involve potential market manipulation, 16 involve potential tariff violations, four involve potential violations of a FERC order and two involve potential violations of a FERC filing requirement.

Staff closed 16 investigations, 11 without further action because of lack of evidence. One of these was into bidding behavior in ISO-NE's eighth Forward Capacity Auction in 2014, the results of which stood because of a tie vote of the commission. Commissioners Tony Clark and Norman Bay had voted to throw out the results. (See *FERC Commissioners at Odds over ISO-NE Capacity Auction*.)

The other five were closed through commission-approved settlements that resulted in more than $51 million in civil penalties. The largest of these, $41 million, was paid by GDF SUEZ Energy Marketing for offering generation below cost to capture make-whole payments in PJM. GDF also disgorged $40.8 million in unjust profits to the RTO. (See *GDF SUEZ to Pay $82M in PJM Market Manipulation Settlement*.)

The settlements also included $2.7 million assessed on K. Stephen Tsingas and $9 million on his company, City Power Marketing, for making risk-free up-to-congestion trades to profit off PJM line-loss rebates. However, the company is defunct, and FERC agreed not to pursue Tsingas for the additional amount. (See *Trader Agrees to Pay $2.7M in Win for FERC*.)

They did not include the $105 million Barclays Bank recently paid to settle claims it manipulated the Western markets a decade ago, which occurred after the end of FY 2017. FERC had originally sought $470 million. (See *FERC Settlement Cuts Barclays Market Manipulation Fine*.)

Asked by reporters on Thursday why FERC agreed to such a steep cut, FERC Chairman Neil Chatterjee said he wanted to avoid years of litigation. "My priority was to get the disgorgement money back to those that have been harmed and deter similar conduct in the future," he said. He noted that the $70 million civil penalty against the bank was the third largest the commission had ever levied. Barclays also disgorged $35 million to states' low-income home energy assistance programs.

FERC NEWS

FERC Pipeline Approval Attracts Celebrity Protest

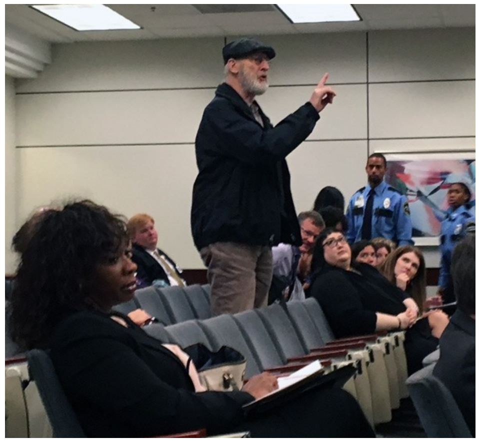
By Michael Brooks

WASHINGTON — Protesters interrupting FERC's monthly open meetings over the commission's approval of natural gas pipelines has become a regular occurrence, but it's not every day they include an Academy Award-nominated actor.

James Cromwell — known for his roles in films such as "Babe," "Star Trek: First Contact" and "L.A. Confidential," among many others — was one of three protesters who interrupted the commission's open meeting Thursday. The 77-year-old actor stood after two other protesters had interrupted FERC Chairman Neil Chatterjee as he began to give his closing remarks. He lambasted the commissioners for destroying the environment as he was led out of the meeting room, and could be heard chanting "FERC doesn't work" as he was led out of the building.

Cromwell, of Warwick, N.Y., later told reporters he had traveled to D.C. with fellow Orange County resident Pramilla Malick to protest the commission's approval of the Valley Lateral Project, a 7.8-mile extension of the Millennium Pipeline through the county. The lateral would serve the 680-MW Valley Energy Center being built in Wawayanda by Competitive Power Ventures.

FERC's approval was especially controversial because it ruled that the New York Department of Environmental Conservation had waived its authority to issue or deny a water quality certification by failing to act under the one-year time frame required by the Clean Water Act. (See *Environmentalists Denounce Millennium Pipeline Ruling*.) Construction of the lateral project has been



Actor James Cromwell addresses FERC commissioners before being escorted out of the meeting room. | *Protect Orange County*

stayed by the 2nd U.S. Circuit Court of Appeals pending a Dec. 5 hearing by a three-judge panel to review New York Attorney General Eric Schneiderman's petition to overturn FERC's decision.

Malick, who was also removed from the meeting for interrupting, was among the petitioners whose request for rehearing of the decision was denied by FERC on Thursday (CP16-17).

She was joined by several other Orange County landowners who argued that the extension is unneeded, in part because the power plant is unlikely to be finished. Malick cited the federal corruption and bribery accusations against a CPV executive and state officials in connection with the state's approval of the plant. (See *CPV Lobbyist, Former Cuomo Aides Named in Bribery Indictment*.)

FERC, however, was unpersuaded. "None of the materials relating to the investigation submitted by Ms. Malick indicate that state approval of the Valley Energy Center is subject to the outcome of any investigation," the commission said. It noted that the facility was 85% complete and on schedule to begin operations by February 2018.

"The whole process has been corrupted," Cromwell told reporters outside FERC headquarters after the meeting. "It should be grounds for stopping the project and having an investigation into how" it was approved.

Malick had argued that FERC violated the National Environmental Policy Act in its environmental assessment by improperly segmenting the pipeline project from Millennium Pipeline Co.'s compressor station in Minisink.

In its Thursday decision, FERC said, "There is no evidence that the Minisink Compressor Station included any facilities to accommodate the future Valley Lateral Project." It pointed out that the station went into service in June 2013, and Millennium first applied for the lateral in November 2015, demonstrating that they weren't connected actions under NEPA.

Cromwell's ejection from FERC is only the latest in a long list of acts of civil disobedience. He made headlines this summer for serving prison time after he refused to pay a fine for a 2015 sit-in at the CPV plant construction site. Days after he got out, he was arrested at SeaWorld San Diego for interrupting a show.

"I've been thrown out of a number of meetings," Cromwell said. "It doesn't matter where it is; it's the same process. They don't listen."

FERC Approves FirstEnergy Sales to Affiliates

FERC last week approved two requests by FirstEnergy Solutions (FES) to sell power to Potomac Edison and West Penn Power. All three companies are subsidiaries of FirstEnergy (ER17-1267, ER17-1272, ER17-1559). The agreements are retroactive to June 1.

FES won the bids through competitive solicitations from the affiliates to serve customers who do not take service from competitive retail suppliers. Potomac serves customers in Maryland and West Virginia; West Penn's customers are in western Pennsylvania.

FERC uses standards set out in its 1991 Edgar Electric Energy (ER91-243) and 2004 Allegheny Energy Supply rulings (ER04-730) to prevent utilities from self-dealing. The commission determined that the affiliate deals met the four criteria of transparency, definition, evaluation and oversight.

No protests were filed over the transactions.

— Rory D. Sweeney

FERC News

FERC OKs Amended Entergy PPAs, Ups Bandwidth Refund

By Amanda Durish Cook

FERC OKs 6 Amended Entergy PPAs

FERC last week accepted six revised power purchase agreements among Entergy subsidiaries following Entergy Arkansas' withdrawal from the company's multistate system agreement.

Entergy sought in May to amend the PPAs, each of which had been previously filed with FERC because they are being transferred under provisions of the company's tariff and involve the Grand Gulf Nuclear Station in Mississippi. Under the tariff that replaces the longstanding Entergy system agreement, the resale of power purchased from Grand Gulf must earn FERC approval.

Entergy Arkansas withdrew from the agreement in late 2013 when it joined MISO; the rest of Entergy's Gulf Coast operating companies followed suit and set staggered dates to abandon the agreement, prompting Entergy to create a company-wide tariff that governs PPAs among its affiliates. (See *FERC OKs 2018 Entergy System Agreement Exit*.) The system agreement had been the basis for planning and operating the Entergy utilities' generation and transmission facilities as a single system since 1982.

In accepting the amended PPAs, the commission determined that the language is similar to Entergy's previously approved agreements and in compliance with Nuclear Regulatory Commission requirements (ER17-1160, *et al.*). In addition to Entergy Arkansas, the PPAs include Entergy Louisiana, Entergy New Orleans and Entergy Mississippi.

The commission also directed Entergy to submit a compliance filing specifying the date on which the amended PPAs began to fall under the new tariff rather than the system agreement. FERC noted that Entergy may have meant to fill in Dec. 19, 2013, the date of Entergy Arkansas' withdrawal from the agreement.


Grand Gulf Nuclear Station | *Entergy*

The commission's order makes the PPAs' acceptance official. FERC staff had provisionally accepted Entergy's filing in June when the commission still lacked quorum.

FERC Orders Compound Interest Refund in Entergy Bandwidth Issue

Entergy's fading system agreement was at the center of another FERC ruling last week when the commission rejected a compliance filing the company made to provide refunds on the bandwidth payments it received from its operating companies (ER10-1350-006). Entergy submitted the filing a year ago to comply with a commission order to calculate interest on refunds related to the payments. (See *FERC: Further Compliance Filings for Entergy, MISO*.)

FERC determined Entergy miscalculated the interest on the refund due back to its Louisiana affiliate. In February 2016, Entergy refunded Entergy Louisiana $27 million in payments, paying the principal but not the interest, and recording the amount in its refund compliance filing. The parent company last November additionally refunded compounded interest, but only up until the Feb. 16 principal payment date. The Louisiana Public Service Commission noticed that Entergy did not pay interest on the initial missing interest payment and protested the filing, asking that interest-on-interest payments of $25,761 be made for most of 2016.

Entergy argued that interest should have only been calculated from the date of collection until the date refunds are made.

FERC last week ordered another compliance filing, ruling that Entergy must "calculate interest compounding on the interest component of the payments at issue until the date the interest payment is actually made."

Entergy's allocation of production costs among its half-dozen operating companies under its system agreement has been a source of disagreement for a decade. Payments are made annually by Entergy's low-cost operating companies to the highest-cost company in the system, using a "bandwidth" solution that ensures no operating company has production costs more than 11% above or below the system average.

FERC NEWS

FERC Won't Rehear Entergy Refund Order on Off-System Sales

By Amanda Durish Cook

FERC last week refused to reconsider how Entergy should calculate ratepayer refunds resulting from Entergy Arkansas' off-system sales to non-Entergy entities from 2000 to 2009. FERC denied rehearing requests from the Arkansas Public Service Commission, the Louisiana Public Service Commission and Entergy (EL09-61-006).

The order stems from a 2012 ruling requiring Entergy to make refunds to ratepayers because it improperly allocated lower-cost system energy in off-system energy sales to third-party power marketers and other non-agreement members between 2000 and 2009. The allocation violated the circa-1982 Entergy system agreement, driving up the rates of captive customers of other operating companies by preventing their purchase of the low-cost energy.

Last year, in Opinion 548, FERC ordered a full rerun of Entergy's intra-system bill that reflects how the purchases should have been priced to determine damages. Final damages have not yet been determined, and the issue is still in hearing procedures. (See *FERC Affirms Entergy Refund Order on Off-System Sales*.)

The commission also affirmed its 2012 Opinion 521, in which it decided that although the opportunity sales in question are not joint account sales — sales to others for the joint account of all Entergy operating companies — they should be given the same treatment under Entergy's responsibility ratio.

It dismissed the Louisiana PSC's argument that FERC erred in requiring that the opportunity sales load be excluded from Entergy Arkansas' responsibility ratio because the subsidiary is solely responsible for the sales.

"The Louisiana commission's interpretation of Opinion No. 521 ignores the commission's full findings," FERC said. "Entergy Arkansas should not have to pay for the capacity used to service the opportunity sales if it did not also have the ability to draw upon the cheaper energy for sales to its own load."

FERC rebuffed Entergy's argument that its remedy was "arbitrary and capricious in deviating from the long line of orders" that held that the system agreement granted each operating company first call on the energy from their generation facilities. "The precedent Entergy cites does not interpret the system agreement with respect to the type of off-system sales at issue in this proceeding," FERC explained.

FERC also found no merit in Entergy's argument that the refund methodology is at odds with provisions of the system agreement that prohibit an operating company from simultaneously buying and selling energy. The commission said Entergy failed twice to point out such a provision in its system agreement.

The commission also declined to decide whether payment for damages should be distributed to ratepayers or shareholders, calling it outside of the scope of proceeding.

FERC Denies BGE Recovery of $38M in Deferred Taxes

By Rory D. Sweeney

FERC denied Baltimore Gas and Electric's bid to recover $38 million in taxes deferred over decades, saying that "contrary to BGE's assertion, we find that utilities do not have unfettered discretion to defer these tax amounts on their books for decades without timely seeking regulatory approval to collect them."

BGE sought approval for three adjustments to its formula rate for how taxes are recovered (ER17-528). The revisions would have returned $4 million to customers related to tax rate changes but also collected approximately $42 million. The collections broke down to $29 million related to deferred tax liability for the equity component of allowance for funds used during construction (AFUDC) and approximately $13 million for an accounting adjustment to claw back tax benefits that were flowed through to customers at the time they originated, rather than relying on BGE's current tax normalization methodology that collects tax liabilities and distributes benefits over time.

FERC said BGE took too long to make the adjustments.

"Although these accumulated amounts may represent legitimate deficiencies in accumulated deferred income taxes, we find that these deficiencies should have been captured in BGE's formula rate since its implementation in 2005," the commission said.

FERC cited 1981's Order 144, which stipulated that all utilities use the normalization methodology. It additionally required them to begin the process of accounting for any tax excesses or deficiencies through rate adjustments. The order called for companies to make the adjustments in their next rate case following the order's implementation or at least "within a reasonable period of time."

"Had BGE properly addressed the tax deficiencies when its formula rate was initially filed in 2005, BGE may have been allowed to collect some portion of these deficiencies over the remaining life of the underlying plant assets that created the deficiencies," the commission said.

BGE's failure to "match" tax effects with the revenues that created them in a timely manner was "particularly noticeable" regarding the flow-through items because they are related to assets from prior to 1976, "most of which have been either fully depreciated or retired by 2016."

"It is unclear if there are any relevant assets left on BGE's books in 2017 to match the amortization period over the next 28 years," FERC said.

FERC NEWS

FERC Rejects NERC Bid to Reduce Transparency

By Rich Heidorn Jr.

FERC last week rejected NERC's request to eliminate public posting of self-reported compliance exceptions and to expand compliance exceptions to include some moderate-risk violations.

"In most situations, information on NERC's resolution of compliance and enforcement matters should be transparent and publicly available," the commission said. The rejections came in an order in which the commission accepted NERC's annual report on its Compliance Monitoring and Enforcement Program (CMEP) (RR15-2-005).

In February 2015, the commission allowed NERC to move to a risk-based approach to compliance monitoring and enforcement, which allowed low-risk violations of reliability rules to be recorded and mitigated without formal enforcement actions. It also allowed registered entities that passed a NERC review of their internal controls to self-log and mitigate minimal-risk violations, subject to periodic, rather than individual, reviews by the Regional Entity. (See *New NERC Enforcement Methods Allow Self-Logging Minor Risk Issues*.)

Incentive Lacking?

NERC said the commission "unintentionally removed an incentive for registered entities to participate in the program" when it required public logging, contending that it had reduced interest in the program.

The Edison Electric Institute, the ISO/RTO Council (IRC) and MISO transmission owners were among those supporting NERC's proposal to eliminate public posting. The IRC noted that only 59 of more than 1,200 registered entities participate in self-logging, saying that the incentives to participate were inadequate.

The American Public Power Association, Electricity Consumers Resource Council, National Rural Electric Cooperative Association and Transmission Access Policy Study Group opposed the elimination of public posting in a joint filing, saying the transparency was needed to educate the industry and preserve the credibility of NERC's enforcement program. They said that because compliance exceptions are a significant percentage of noncompliance, the public disclosures allow registered entities to understand compliance requirements. They also said the public posting could help identify unnecessary or redundant reliability requirements.

The commission said it agreed with the commenters who supported continued public disclosure. "The value of maintaining the transparency of self-logged noncompliance continues to outweigh the asserted benefit that might accrue from increasing the incentive to participate in the program," FERC said, citing the "minimal" burden of public posting and the benefits it provides in "educating industry and ensuring consistency across NERC's and the Regional Entities' compliance and enforcement programs."

Find, Fix and Track Program

FERC also rejected NERC's proposal to expand the compliance exceptions program to include moderate-risk noncompliance, although all commenters supported NERC's request.

Moderate-risk violations that have been corrected are currently subject to the Find, Fix and Track (FFT) program, which allows NERC to process them through informational filings instead of the formal Notice of Penalty procedure.

"We are not persuaded that the claimed efficiency gains in processing certain moderate-risk violations as compliance exceptions, rather than as FFTs, are sufficient to outweigh our concerns with treating many moderate-risk noncompliances through a nonenforcement track," FERC said. "While this approach may be appropriate for minimal risk violations, NERC has not adequately justified this limited approach for moderate-risk violations."

The commission also raised questions about the FFT program, saying its staff had identified a compliance exception involving falsification of battery testing records by a registered entity's employee that was disposed of via the FFT process. "The commission does not consider it appropriate to process instances of noncompliance involving falsification of records as compliance exceptions or FFTs," it said. "Rather, such circumstances warrant a full Notice of Penalty."

NOPR on Training, Coordination of Protection Systems

In a separate Notice of Proposed Rulemaking, the commission proposed reliability standards PRC-027-1 (Coordination of Protection Systems for Performance During Faults) to ensure protection systems used to detect and isolate faults operate in the intended sequence.

The NOPR also proposed the approval of reliability standard PER-006-1 (Specific Training for Personnel) to ensure that personnel involved in real-time operations are adequately trained (RM16-22).

Cauley Resigns; NERC Launches Search for Replacement

Continued from page 1

cybersex with a "young female employee of his." (See *Cauley Arrest Tied to Relationship with NERC Subordinate*.)

Jean, a former probation officer and child abuse investigator for the state of Florida, posted a comment about the incident on her LinkedIn page Sunday: "Who knew that when I married a CEO — and me with a background in law-enforcement — [I] would be a victim of a violent crime by her husband to the point of a back being broken," she wrote. "It shows that no one is exempt from domestic violence and that we should all support each other as women."

Cauley, 64, had served as NERC CEO since January 2010, and was often the face of the reliability agency in hearings before FERC and Congress. By Monday afternoon, however, his biography and photo had been removed from the web page listing the organization's management.

FERC NEWS

Ukraine Attacks, 'Fake News' Color NERC GridEx IV Drill

By Rich Heidorn Jr.

NERC led a media briefing on GridEx IV Thursday. Clockwise from bottom: Kimberly Mielcarek, NERC; Charles Berardesco, NERC; Patricia Hoffman, DOE; Kevin Wailes, Lincoln Electric System; Tom Fanning, Southern Co.; Duane Highley, Arkansas Electric Cooperative Corp.; Marcus Sachs, NERC. | *NERC*

Participants in NERC's GridEx IV began the two-day drill Wednesday encouraged by their coordination in recent hurricanes but chastened by the 2015 cyberattack on the Ukraine and the spread of disinformation via social media.

About 6,500 participants from 450 organizations took part in GridEx IV, including electric utilities, RTO officials, regional and federal government officials, first responders and intelligence agencies.

"The large-scale cyber and physical attack scenario is designed to overwhelm even the most prepared organizations," NERC Acting CEO Charles Berardesco said during a media briefing Thursday morning. "Participating organizations are encouraged to identify their own lesson learned and to share them with NERC."

Most of the participants are involved in two days of "distributed play" across the U.S., Canada and Mexico. In addition, about 100 executives gathered at Booz Allen Hamilton in Washington on Thursday for a "tabletop" exercise run in parallel.

Officials at CAISO's Joint Information Center respond to "injects" during GridEx IV on Wednesday. | *CAISO*

"The usefulness of these exercises is [testing] the unknown and heretofore unseen. It is to break the system. It is to find out where the friction points are [and] trying to harmonize the activities [of] the federal government, private industry and state and local governments," said Southern Co. CEO Tom Fanning, co-chair of the Electricity Subsector Coordinating Council (ESCC). "It'll be a great day. We'll learn a lot."

Previous Lessons Learned

Fanning said previous GridEx drills improved industry coordination, as he said was demonstrated in the "unprecedented collaboration" among investor owned utilities, cooperatives and municipal utilities following hurricanes Harvey and Irma in August and September.

"The ESCC also has a responsibility for helping to coordinate storm response," he said. "I think this model is working exceptionally well. In fact, we believe the metrics would show that our recovery times were roughly half of what they have been for similar storms in the past." Hardening of infrastructure also contributed to the speed of the storm recovery. (See *Power Restored for 97% of Customers in Irma's Wake*.)

"You get good at what you practice, and we want to be good at response recovery," said ESCC Co-Chair Duane Highley, CEO of the Arkansas Electric Cooperative Corp., who noted that about 50 cooperatives were participating. "And we want to build our relationships before we need them."

ESCC Co-Chair Kevin Wailes, CEO of Lincoln Electric System, said a key improvement resulting from the 2015 drill was the creation of a cyber mutual assistance group. "We realized that we really did not have a deep enough bench … to deal with some of these events on an individual basis," he said. "So we now have 130 companies involved in cyber mutual assistance."

The 6,500 participants represented an almost 50% increase from GridEx III. (See *GridEx III Shows Vulnerability of Power Grid to Cyberattack*.)

This year's iteration of the biennial exercise is the first to involve the finance, telecommunication and natural gas sectors in the tabletop exercise.

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FERC NEWS

Ukraine Attacks, 'Fake News' Color NERC GridEx IV Drill

Continued from page 36

NERC officials participate in GridEx IV on Wednesday. | *NERC*

'Real World' Scenarios

The "injects" — or scenarios — were informed by the cyberattack that knocked out power to 225,000 customers in Ukraine for several hours in December 2015. (See How a 'Phantom Mouse' and Weaponized Excel Files Brought Down Ukraine's Grid.)

"We always take real-world events as the basis for the exercise because the engineers that are running the distributed play … know what the vulnerabilities are," said Marcus Sachs, NERC senior vice president and chief security officer.

"We will name specific vendors and components, so it's a very realistic type of exercise."

"There's been a lot of operational planning and coordination since Ukraine in 2015 between government and industry," said Chris Krebs, the Department of Homeland Security's acting undersecretary for national protection and programs. "So this is a fantastic opportunity for us to start stress testing some of those planning assumptions we've made."

In recognition of revelations about a Russian campaign to spread "fake news" during last year's presidential election, officials said they also were incorporating the threat of disinformation on social media platforms.

"The unity of message … is just about as important as the unity of effort. That is, we've got to make sure we understand … how we advance our communications," said Fanning. "An important aspect of that … is how do we gain more influence and control on social media."

Cauley Absent

GridEx IV was the first such drill run without longtime NERC CEO Gerry Cauley, who was removed from his post Nov. 11 and resigned Monday following his arrest on domestic violence charges. (See related story, *Cauley Resigns; NERC Launches Search for Replacement*, p.1.)

NERC spokeswoman Kimberly Mielcarek cut off Berardesco before he could answer a question about how he kept the Cauley situation from being a distraction going into the exercise.

"We're keeping staff informed as developments unfold," she said. "It's premature for us to comment on anything further at this time. However, we do provide updates as they are available, and we will continue to do so both publicly and to our staff."

About 100 utility officials and others participated in the executive tabletop portion of GridEx IV at Booz Allen Hamilton in D.C. | *NERC*

Hopes for 2017 Drill

Patricia Hoffman, principal deputy assistant secretary for the Department of Energy's Office of Electricity Delivery and Energy Reliability, said she hoped this year's drill would test the energy secretary's emergency authority. Section 202(c) of the Federal Power Act allows the secretary to order power plants to operate for reliability reasons during emergencies. It has been used infrequently, notably during the Western Energy Crisis in 2000 and after Hurricane Katrina in 2005.

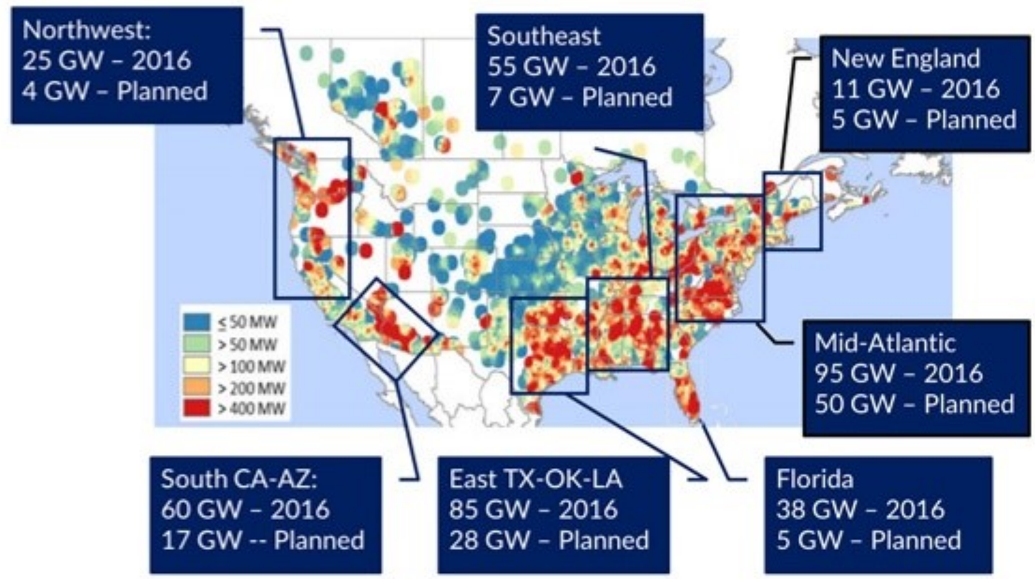
The drill "also helps with us as we look at how we're planning for modernization and investment in the infrastructure moving forward," she said.

A report on the drill will be released in about March 2018.

FERC NEWS

NERC: Natural Gas Dependence Alters Reliability Planning

Continued from page 1



* All values are approximates, various sources: EIPC, EIA-860, NERC LTRA

tial harm to the electric sector.

The report, "Special Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System," listed several key mitigation strategies, including transmission upgrades, dual-fuel capability, power imports, adding incremental and diverse generating resources, firm fuel agreements and battery storage.

NERC said the power sector is seeing a drop in the number of dual-fuel units. Developers are foregoing the added expense of dual-fuel capability in many new projects, it said.

It also suggests dual fuel, backup pipeline capacity, and alternative sources of supply should be required in areas with significant risk.

"Dual-fuel capability increases generation reliability and resilience," the report said, noting dual fuel is currently limited by environmental regulations restricting how long plants can run on oil. NERC called for temporary air permit waivers before any "sustained natural gas infrastructure disruption," saying waivers should be incorporated into "resilience-planning initiatives when they are required."

The assessment does not directly take on the Department of Energy's directive that FERC strengthen the grid's resiliency by propping up the finances of coal and nuclear plants, but it does point out the growing importance of natural gas as a fuel supply.

"Natural gas resources have become much more diversified," Tom Coleman, NERC's director of reliability assessments, said during a media conference call. "Twenty years ago, we were more reliant on Gulf [of Mexico] supplies. We have much more shale gas in some of the market areas that has really changed the dichotomy. Due to this diversity, we don't have the same risks we had 20 [or] 25 years ago."

The report offers recommendations to policymakers, the industry and NERC itself. It calls for regulators to consider fuel diversity when they evaluate system plans and establish energy policy objectives. It also recommends expedited licensing of new transmission and natural gas facilities to diversify risk.

NERC suggests registered entities consider the loss of key natural gas infrastructure in their planning studies, and that the gas and electric industries increase coordination and information sharing "to promote reliability and interdependent system integrity."

"As our power supply becomes increasingly dependent on natural gas, industry must ensure this just-in-time fuel is as reliable and secure as the power plants that need the fuel to operate," the assessment says.

The organization also recommends adding planning and operating requirements for analyzing disruptions to its reliability standards. To mitigate common causes of failure, it said its Generator Availability Data System (GADS) database should begin collecting additional information on the duration, frequency and causes of natural gas outages.

NERC conducted the assessment by reviewing existing studies, evaluating gas storage facilities and identifying generation clusters — areas with at least 2 GW of gas generation — to determine potential vulnerabilities.

Coleman said the organization studied 24 areas, 18 of which "demonstrated the need for additional follow-up and analysis, based on power flow and stability issues" of the "extreme cases" it ran.

"We wanted to develop a bookend, a worst-case scenario," he said.

Coleman said natural gas demand has "altered the storage dynamics," which have historically operated as an inventory hedge by injecting in the summer and withdrawing in the winter.

"With much more electric generation out there, we're seeing more of an annual injection and withdrawal cycle, versus just a winter and summer dichotomy."

The report was received coolly by the American Petroleum Institute, which called it "a missed opportunity to properly examine ways to improve the reliability and resilience of North America's electric grid."

It said NERC acknowledged "that natural gas supply disruptions are extremely rare events and … that industry is taking steps to prevent such disruptions."

It cited its joint report with the Natural Gas Council on resilience, which was released in July.

COMPANY BRIEFS

Clean Line Asks Missouri Supreme Court to Rule on Tx Project

Clean Line Energy Partners has asked the Missouri Supreme Court to rule on its planned Grain Belt Express transmission project, a 780-mile line that would transport 4,000 MW of wind power from western Kansas to the western border of Indiana.

After the Missouri Public Service Commission in August for the second time rejected the company's request for a certificate of necessity and convenience for the project, Clean Line appealed the ruling to the eastern division of the Missouri Court of Appeals.

Rather than wait for a ruling from that court, Clean Line has asked the state Supreme Court to issue a ruling in the case.

More: *Midwest Energy News*

Avangrid Gives Conn. $2M for Vehicle Rebate Program

Avangrid has provided the state of Connecticut with $2 million to continue the Connecticut Hydrogen and Electric Automobile Purchase Rebate program, which provides direct financial incentives of up to $5,000 for state residents who purchase or lease a new zero-emission vehicle.

The company provided the funding as part of a broader commitment to support energy efficiency, renewable generation, energy storage, alternative transportation and other clean technologies in Connecticut.

More: *Avangrid*

Siemens to Cut 2% Of Global Workforce

Siemens announced it will cut about 6,900 jobs, or nearly 2% of its global workforce.

About 6,100 of the cuts will come at Siemens' Power and Gas division, which supplies turbines for power generation and has been hit hard by the rise of renewables.

Siemens' Process Industries and Drives division, which makes large mechanical drives for oil and gas extraction and turbines, will also be hit.

More: *Reuters*

Lawsuit Alleges Utilities Manipulated Gas Capacity

Eversource Energy and Avangrid have been accused in a class-action lawsuit of manipulating capacity in New England's natural gas transmission network so they could overcharge 7.1 million electric customers $3.6 billion between 2013 and 2016.

The suit was filed last week in U.S. District Court in Boston by law firm Hagens Berman Sobol Shapiro. It appears to be based on a report released last month by the Environmental Defense Fund that claims the companies manipulated capacity by scheduling more natural gas deliveries than they needed and then canceling some too late in the day for the space that would have been taken up by the deliveries to be resold.

More: *New Haven Register*

Central Maine Power CEO Burns to Retire

Avangrid's Central Maine Power subsidiary said Thursday that CEO Sara Burns will retire at the end of the year.

Burns also will step down from her roles overseeing asset management and planning, business development and regulatory strategy for Avangrid Networks but will join its board of directors in January 2018.

CMP said a search for Burns' replacement is underway under Avangrid's succession-planning process.

More: *Mainebiz*

Sunverge Appoints Milani as CEO


Milani

Residential energy storage system developer Sunverge Energy has named Martin Milani its CEO.

Milani had been Sunverge's chief operating officer and chief technology officer since December 2016.

In his new role, Milani will lead the development of Sunverge's cloud and edge software for managing distributed energy resources and smart home devices.

More: *Energy Storage News*

PPL Subsidiary Closing 2 Kentucky Coal-Fired Units

LG&E and KU Energy said last week it will close two coal-fired units at the Kentucky Utilities E.W. Brown Generating Station near Harrodsburg, Ky., in February 2019.

The PPL subsidiary will continue operating a newer, larger coal-burning unit, solar farm and hydroelectric plant at the complex.

The units to be shuttered date to 1957 and 1963 and don't have the latest air pollution controls.

More: *The Courier-Journal*

Dynegy Finds Buyer for Decommissioned Plant

Dynegy has selected a buyer for the decommissioned Brayton Point Power Station in Somerset, Mass.

The company wouldn't name the buyer, but state Sen. Michael Rodrigues (D) said it is a St. Louis company "that is very experienced … in buying old, heavily industrialized sites, cleaning them up and getting them ready for future redevelopment."

Dynegy said a contract on the property should be signed soon.

More: *The Herald News*

Enel Starts Building Wind Farm, Turns on Another

Enel Green Power North America said it has started construction of the Rattlesnake Creek wind farm, which will provide 100% of the energy for Facebook's new data center in Papillion, Neb.

The wind farm, Enel's first in Nebraska, will have an installed capacity of 320 MW when finished.

The company has also announced the start of operations of its 300-MW Rock Creek Wind Farm, which is the largest operational wind farm in Missouri.

More: *North American Windpower*

Federal Briefs

Group Fighting DOE NOPR Begins Revealing Members

The Affordable Energy Coalition, which is urging FERC to reject the Department of Energy's Notice of Proposed Rule Making to subsidize certain coal and nuclear plants, has begun revealing the identities of its members.

The organization announced its existence two weeks ago but didn't name its members.

Of the members it identified, only one, BP, is a corporation. The other named members are Advanced Energy Economy, the American Wind Energy Association, the Electricity Consumers Resource Council, Energy Storage Association, Industrial Energy Consumers of America and the R Street Institute, a free-market think tank.

More: *Axios*

TVA CEO: Options for Moving Coal Ash Cost up to $2B

Gallatin Fossil Plant

Complying with a court order to move coal ash from unlined and leaking pits and ponds to a lined landfill on the site of the Gallatin Fossil Plant would cost $900 million and take 24 years, said Bill Johnson, CEO of the Tennessee Valley Authority, which owns and runs the plant.

A less-preferred option, moving the coal ash offsite, would cost $2 billion, Johnson said.

The Southern Environmental Law Center disputes the estimates.

More: *The Associated Press*

Unions: Plant Contractor Violating Tribal Employment Law

Unions that represent Navajo workers say tribal members are being passed over for temporary jobs installing emissions control equipment at the Four Corners Power Plant in violation of the tribe's Navajo Preference in Employment Act.

The plant is on land leased from the Navajo Nation by Arizona Public Service, which runs the power plant. An APS spokesman said contractors and subcontractors working on the project to install the equipment, which costs $635 million and requires nearly 1,500 temporary workers through July, must abide by tribal law.

AECOM, which is overseeing the installation of the pollution controls, declined to comment.

More: *The Associated Press*

DOE Reactivates Facility For Testing Nuclear Fuel

TREAT reactor

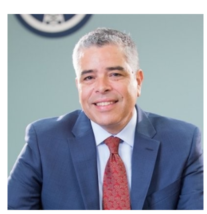
The Department of Energy last week began testing the equipment at the Transient Reactor Test Facility, which has been on standby status since 1994.

The facility, which is located at the Idaho National Laboratory in eastern Idaho, is used to test fuel used in nuclear reactors.

Department officials hope the facility will help researchers create fuels that leave behind less nuclear waste, are harder to turn into weapons and are less likely to lead to reactor core meltdowns.

More: *The Spokesman-Review*

PREPA Director Ramos Resigns



Ramos

Ricardo Ramos, executive director of the Puerto Rico Electric Power Authority, resigned Friday, nearly two months after Hurricane Maria left much of the island without electricity.

Ramos said his resignation was a personal decision unrelated to media coverage, which has focused on the slow pace of PREPA's power restoration efforts and its decision to contract Whitefish Energy to handle restoration on the island.

Gov. Ricardo Rosselló told reporters Friday that Ramos had become a "distraction" and his tenure "unsustainable."

More: *CNN*

PNNL, National Grid Agree To Collaborate on Research

The Department of Energy's Pacific Northwest National Laboratory and National Grid have agreed to work together on research in the areas of transmission grid modernization and energy storage technologies, as well as collaborate in other ways.

Research areas the two will tackle include grid-scale energy storage; advanced transmission network controls and monitoring; distributed and variable energy resource integration; and enhanced grid cyber-protection.

The two also will hold joint workshops, lectures and symposia, and will use other forums to promote enhancements in technology, education and industrial development related to grid modernization and energy storage.

More: *Pacific Northwest National Laboratory*

ALEC Mulling Bid to Change EPA on Endangerment Finding

ALEC American Legislative Exchange Council LIMITED GOVERNMENT • FREE MARKETS • FEDERALISM

The American Legislative Exchange Council (ALEC) will consider a resolution that it would offer to state legislatures to get them to prod EPA to rescind its determination that climate change is a risk to human health and welfare.

That determination, which EPA made in 2009, is the justification for the agency promulgating regulations on carbon emissions.

ALEC receives funding from Koch Industries and Peabody Energy. It has other members that don't wish to take a position against climate-change regulation and the resolution could prove divisive.

More: *Bloomberg Politics*

STATE BRIEFS

CALIFORNIA

Ethics Commission Investigating Former PUC Commissioner


Kennedy

The Fair Political Practices Commission has requested letters, emails, calendars and other communications between the Public Utilities Commission and two businesses owned by Susan Kennedy, a former commissioner and founder and CEO of Advanced Microgrid Solutions.

Kennedy, a former aide to Govs. Gray Davis and Arnold Schwarzenegger, also owns Susan P. Kennedy Inc. and political consulting firm Caliber Strategies. The FPPC seeks all communications between the two companies and the PUC, as well those with Manal Yamout, senior vice president of policy at AMS. Yamout is also a former adviser for Schwarzenegger and a former partner with Caliber.

An FPPC spokesperson said he could not discuss the details of the investigation, but the request document references Kennedy's consulting work for several companies.

More: *The San Diego Union Tribune*

COLORADO

Whistleblower Sues Colorado Springs for Defamation


Weise

Leslie Weise has filed a lawsuit in U.S. District Court in Denver alleging that Colorado Springs, some of its current and former council members, a city attorney and a spokeswoman for the city-owned utility defamed her for "exposing the fact that the Martin Drake Power Plant was spewing noxious pollution in violation of Environmental Protection Agency regulations."

The suit says the actions against Weise began after she told a reporter for *The Gazette* that an air-quality report by Colorado Springs Utilities, which owns the power plant, showed that the organization was aware of toxic levels of sulfur dioxide emissions from the plant.

More: *The Gazette*

MASSACHUSETTS

State Issues RFP for Small Solar Development

The state has issued its first request for proposals under the Solar Massachusetts Renewable Target (SMART) program, which is designed to provide incentives for solar projects of 5 MW or less.

The program will pay rooftop solar customers incentives that the customers can combine with the state's net metering program. It also will pay specific rates for projects on landfills, brownfields and solar canopy structures.

Proposals under the program will be accepted from Nov. 27 to Dec. 5.

More: *pv magazine*

MINNESOTA

Loggers and Truckers Group Sues To Block Closure of Biomass Plant

The Associated Contract Loggers and Truckers of Minnesota has sued to block closure of a biomass power plant in Benson.

Xcel Energy has received authorization from the Legislature to cancel its power purchase agreement with the plant and is asking the Public Utilities Commission to approve the cancellation, which it says would save consumers money.

The lawsuit asks the court to order a study of the environmental impacts of closing the plant, which it calls an important market for waste wood.

More: *The Associated Press*

NEBRASKA

PSC Approves Alternative Keystone Pipeline Route

In a 3-2 vote, the Public Service Commission approved a route for the Keystone XL Pipeline across the state, but not the route preferred by TransCanada, the pipeline's developer.

The approved route takes a 63-mile detour from the route that TransCanada wanted. That likely will make building the 36-inch crude oil pipeline more expensive and require TransCanada to sign new right-of-way contracts with about 40 landowners, some of whom may not know their land is on a pipeline route.

Even if TransCanada can overcome those obstacles, the PSC's approval doesn't mean the pipeline will get built. Pipeline opponents have promised to file lawsuits to challenge it, and TransCanada has said it won't decide until December if it has enough shippers to make the $8 billion project financially feasible.

More: *Omaha World-Herald*

State Senator Seeks Moratorium on Wind Development in Sandhills

State Sen. Tom Brewer plans to introduce a bill next legislative session that would place a two-year moratorium on wind development in the Sandhills.

Landowners fear that a 225-mile transmission line that the Nebraska Public Power District is proposing to build is meant to increase wind development, which NPPD denies.

More: *KMTV*

Omaha Public Power District to Seek up to 300 MW of Wind

Omaha Public Power District CEO Tim Burke said the utility is working on a request for proposals for up to 300 MW of wind energy.

With the wind power obtained from the RFP, more than half the energy the utility sells to retail customers will come from renewable sources by the end of 2020.

Less than 20% of OPPD's retail power sales in 2016 came from renewable sources.

More: *Omaha World-Herald*

NORTH DAKOTA

PSC Votes to Advance Four Wind Projects

The Public Service Commission unanimously voted on Thursday to advance four wind power projects.

The commission issued an amended siting

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Chatterjee: 'We've Moved Past' DOE NOPR

Continued from page 1

been working on for an interim step coupled with our own long-term rulemaking." (See DOE, Pugliese Press 'Baseload' Rescue at NARUC.)

He said he was "cognizant" of the criticisms the NOPR has received, but that "people are still debating the NOPR as it was submitted to us. And what I'm trying to say is we've moved past that and we're moving towards a constructive solution that still answers the questions that Secretary Perry asked in the NOPR in a way that does not distort markets and is legally defensible."

Chatterjee revealed he was working on an interim solution this month. (See Chatterjee to Push Interim 'Lifeboat' for Coal, Nukes.)

He said he is contemplating proposing a "show cause" order requiring grid operators to compensate resources that may provide resilience benefits and are at risk of retirement as an interim measure while the commission conducts a longer-term rulemaking.

Chatterjee called on his critics to "calm down," attributing their "hyperbolic" reaction to a lack of understanding of his plan.

"This is a very careful, thought-out approach that I think that when people have the opportunity to calmly look at it, there's nothing controversial or radical."

Chatterjee said it was "befuddling" that anyone would find it controversial for the commission to "carefully and thoughtfully" examine the long-term implications of not having coal and nuclear as part of the country's generation mix. He emphasized repeatedly that his "lifeboat" plan was a work in progress but that it would be ready to act on by the DOE-stipulated Dec. 11 due date.

"We're still fleshing it out," he said. "It's incredibly complex; I want to get it right, and as soon as it's right and it's ready and I've had time to review with my colleagues, I'll discuss it in far greater detail at that time."

Chatterjee said that in working on his idea, he has been trying to ameliorate concerns raised by Commissioners Cheryl LaFleur and Robert Powelson about the DOE NOPR.

"I'm hoping that in fleshing this out, [Chatterjee and his staff] will answer the questions and concerns my colleagues had and have a product that we'll be able to build a consensus around," he said.

Chatterjee has previously stated that he has not discussed his idea with the other commissioners.

He also said that he has not reviewed the price-formation proposal PJM released Wednesday — a longer version of what the RTO filed at FERC in comments on the NOPR. (See Rule Changes Could Spur $1.4B Jump in PJM Market Costs.)

"It's certainly in line with the conversation that we're having," Chatterjee said. "It seems like something that we could look to for a longer-term solution. … But I still remain committed to doing something in the short term, in the interim, while we work towards some of the long-term issues that PJM acknowledged we have."

A Farewell Address, of Sorts

In his remarks opening Thursday's meeting, Chatterjee highlighted what the commission has done since he became chairman in August, including changes in hydropower licensing, proposals for improved cybersecurity and approval of 8 Bcfd of new natural gas pipeline capacity. (See FERC Sets 40-Year Term for Hydro Licenses and FERC Seeks Cyber Controls on Portable Devices; Sets GMD Plans.)

He said the DOE NOPR would be "the most significant issue we will face during my time on the commission."

Thursday's meeting was Chatterjee's last as chair, with incoming Chair Kevin McIntyre set to join FERC "any day now." McIntyre, along with Democratic Senate aide Richard Glick, were confirmed by the Senate two weeks ago and are awaiting their signed commissions from President Trump.

Heaping praise on FERC staff, Chatterjee also touted the 344 orders that the commission has voted on since the restoration of its quorum. He said there were only "a few odds and ends" left before the commission had eliminated the backlog of filings from its time without a quorum.

"I think it's safe to say that FERC is working harder than ever for the American people," Chatterjee said. "It's been my distinct honor to be the one at the helm overseeing the accomplishments I've outlined today. I'm humbled by the experience and grateful to President Trump for entrusting me with this responsibility."

He closed out the meeting by noting the "unorthodox" nature of his tenure: beginning as chair before going to regular commissioner.

"Doing it in reverse, I actually hope that the experience that I've had will help me be a more effective commissioner going forward," he said, receiving applause after adjourning the meeting.

STATE BRIEFS

Continued from page 41

permit requested by EDF Renewable Development for the 150-MW Merricourt wind project in Dickey and McIntosh counties, and a notice of opportunity for a hearing on Xcel Energy's application for a certificate of public convenience and necessity for its 150-MW Foxtail wind project 20 miles west of Ellendale.

The commission also granted an advanced determination of prudence and an amended CPCN requested by Montana-Dakota Utilities to expand the Thunder Spirit Wind project, a 107.5-MW project northeast of Hettinger, by 48 MW. And it provided an amended siting permit that allows ALLETE Clean Energy to make its project in in Morton and Mercer counties 106 MW, up from 100 MW.

More: The Bismarck Tribune

VIRGINIA

Agency Approves Proposed Rule to Put State in RGGI

The Air Pollution Control Board on Thursday approved a draft proposed rule that would lead to the states joining nine others in the Regional Greenhouse Gas Initiative, the nation's longest-running carbon market.

The rule would cap emissions from the state's electricity sector beginning in 2020 and reduce them by 30% over a decade.

More: InsideClimate News