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FERC Rules to Boost Storage Role in Markets

Commission Delays Action on DER Aggregation

By Michael Brooks

WASHINGTON — FERC on Thursday ordered RTOs and ISOs to revise their tariffs to allow energy storage resources full access to their markets, a move the commission said will enhance grid resilience (RM16-23).

The rulemaking requires each RTO/ISO to establish a "participation model" for storage resources to ensure they are eligible to provide all energy, capacity or ancillary services of which they are capable, while also enabling them to set clearing prices as both a buyer and seller. Grid operators will also need to establish a minimum threshold for participation that doesn't exceed 100 kW.

FERC also required that storage resources be able to resell electricity into the markets at the wholesale LMP.

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FERC Finalizes Frequency Response Requirement (p.39)

NARUC Winter Policy Forum

Former Washington state regulator Phil Jones, NERC's Tim Roxey, Dragos CEO Robert M. Lee and James Hempstead of Moody's Investors Service during a panel on cybersecurity at the NARUC Winter Policy Forum in D.C. last week.
See pages 3-6 for full coverage.

Mass. Picks Avangrid Project as Northern Pass Backup

By Michael Kuser

Avangrid announced Friday that Massachusetts has selected the transmission project of its subsidiary, Central Maine Power, as the alternative for the state's 9.45-TWh clean energy solicitation if New Hampshire regulators do not approve the Northern Pass transmission line by March 27.

Massachusetts awarded the contract to Eversource Energy and Hydro-Quebec's Northern Pass on Jan. 25, only to see the New Hampshire Site Evaluation Committee (SEC) unanimously reject the 1,090-MW transmission project a week later. Eversource appealed the decision, saying in a statement Feb. 16: "We have a strong legal argument for a reconsideration by the SEC." (See *New Hampshire Rejects Permit for Northern Pass*.)

CMP and Hydro-Quebec's New England Clean Energy Connect (NECEC) transmission project would deliver up to 1,200 MW

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FERC Orders New Rules for Supplemental Tx Projects in PJM

By Rory D. Sweeney

PJM transmission owners' processes for developing supplemental projects violate Order 890's transparency and coordination requirements, FERC ruled Thursday in a victory for customers — and, potentially, competitive transmission developers (EL16-71, ER17-179).

PJM stakeholders have been battling for years with TOs over the rules involving supplemental projects — transmission expansions or enhancements not required for compliance with PJM system reliability, operational performance or economic criteria. TOs can develop, build and seek reimbursement for such projects without the approval of PJM, which only reviews them to ensure they don't harm reliability.

Since 2012, according to an analysis produced for American Municipal Power, PJM's $11.6 billion in baseline and network upgrades have been exceeded by $12.7 billion of transmission owner-identified (TOI) supplemental projects.

"I've frequently spoken about my concern about … the amount of transmission spend[ing] that is directed to categories that are not subject to competitive bidding under Order 1000 and in some cases subject to very little planning that's done privately by the transmission owners," Commissioner Cheryl LaFleur said at Thursday's open meeting. "It's obviously our responsibility to make sure that if customers are paying for trans-

Commissioner Cheryl LaFleur before FERC's open meeting Thursday | © *RTO Insider*

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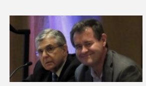

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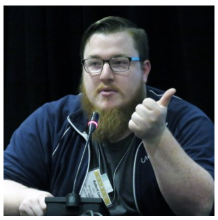
NARUC Winter Policy Summit

Expert Sees 'Extreme Uptick' in Cyberattacks on Utilities

By Rich Heidorn Jr.

WASHINGTON — The cybersecurity expert whose firm discovered the malware that caused blackouts in Ukraine in 2016 told state regulators that hackers targeting the U.S. electric industry are growing more numerous and more skilled.



"There are five dedicated teams targeting infrastructure sites in North America, including eight different campaigns targeting sites," **Robert M. Lee**, CEO of cybersecurity firm Dragos, told the National Association of Regulatory Utility Commissioners' Winter Policy Summit on Feb. 11. "This is an extreme uptick."

In June, Lee's company identified malware it named CrashOverride as the likely cause of a disruption in December 2016 that cut one-fifth of Kiev's power consumption for an hour. (See *Experts ID New Cyber Threat to SCADA Systems*.)

The attack occurred about a year after the December 2015 attack on Ukraine — the first time hackers had taken down a portion of the power grid. The 2015 attack used the BlackEnergy program, which highjacked the supervisory control and data acquisition (SCADA) systems, taking control of operator workstations and locking the operators out.

CrashOverride — which can control circuit breakers without any manual involvement — takes advantage of the simplicity of SCADA. "CrashOverride was just knowledge of the 2015 attack getting codified in malware to make it scalable," Lee said. "A lot of times we tell ourselves, 'There's computer vulnerabilities; if we patch the computer vulnerabilities, we're OK.' But that's not the actual risk. … [The 2016 Ukraine attack] was just adversaries learning the industrial systems and using them against themselves — almost becoming malicious insiders even though they were remote."

The 2016 outage lasted only an hour. But, Lee said, CrashOverride is still dangerous because it "can work without any modification across all of Europe, most of the Middle East and most of Asia."

The malware is an illustration of the increasing sophistication of hackers, Lee said. As recently as 2014, he said, there were only two campaigns against infrastructure sites. 2015 saw not just the first attack on Ukraine but also a cyberattack that caused physical damage at a steel mill in Germany — only the second attack to produce such results, after the Stuxnet attack on Iran's nuclear centrifuges.

Last year, the first known malware specifically targeting industrial safety systems was identified, Lee said. The malware, which targets Schneider Electric's Triconex safety instrumented system, was deployed against at least one victim in the Middle East. "It was going after safety systems in oil and gas production facilities. The only purpose of a safety system is to protect human life. If you go after it willfully … you are either intending to kill people or you're just OK with doing so."

Lee said grid operators and other industries face two strategic challenges. "We don't truly understand or appreciate our industrial threat landscape," he said. "So, we get a lot of best practices or compliance standards written off of business network security, not industrial network security to address the real risk.

"The second challenge is there's not a lot of people who are industrial cybersecurity experts. The Department of Homeland Security puts that at around 500 people in North America … so you're not going to scale that across the industry."

Lee said small electric cooperatives and water utilities may be particularly vulnerable because of their limited staffs. He said his company has done "charity" work for one small water utility where "the one IT guy actually mows the lawn on Fridays."

Tim Roxey, NERC's chief security officer, said there are fewer than 500 people who have the necessary cybersecurity expertise and understanding of both NERC's Critical Infrastructure Protection standards and federal government rules.

"You don't find a whole lot of beer conversations around the bar about the Administrative Procedures Act, and yet these things are fundamental … to how we actually … develop the standards, implement the standards [and] enforce the standards," he said.

There is some good news on that front, however. In an earlier presentation at the NARUC meeting, Dennis P. Gilbert Jr., Exelon's chief information security officer, reported on his company's adoption of the National Initiative for Cybersecurity Education (NICE) Workforce Framework. Developed by the National Institute of Standards and Technology, the program provides organizations with a common lexicon for describing cybersecurity careers by category, specialty area and work role. It involves creating new job titles and performing a market salary assessment.

Gilbert said Exelon was happy to reward many of their cybersecurity team members with 10 to 35% pay raises, citing better morale and a lower attrition rate of 5% — reducing the costs of having to recruit and train new workers in the "high demand, low density" career field.

How Moody's Measures Cyber Risks

Jim Hempstead, managing director of Moody's Investors Service's Global Infrastructure Finance Group, who shared the panel with Lee and Roxey, explained how cyber risks figure in credit rating agencies' evaluation of companies' ability to pay their debts.

"We do not explicitly incorporate cyber risks into the credit analysis for the utility industry or for any of the other" industries, Hempstead said. "The transparency and disclosure around cyber risks are unreliable. There's just not enough disclosure as to what the events are. And there's not enough disclosure as to what is actually happening behind it."

Instead, Hempstead said, Moody's conducts scenario analyses that treat cyberattacks like extreme weather — a low-probability, high-impact event.

"We have seen over and over again utility companies that are able to absorb the impact of a severe event that in many instances has significant financial consequences, but the company is still able to right itself and put itself back on track.

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NARUC Winter Policy Summit

Overheard

WASHINGTON — Resilience, pipelines and the Public Utility Regulatory Policies Act topped the discussions at the National Association of Regulatory Commissioners' winter meetings last week, which were attended by hundreds of state regulators, utility officials and other industry stakeholders. Here are some of the highlights:

'Beacon of Stability'

All five FERC commissioners spoke about grid resilience and how RTOs and ISOs should plan to address it.

Commissioner **Neil Chatterjee** said he hoped FERC's response to the Department of Energy's Notice of Proposed Rulemaking assuaged some fears about the commission's impartiality.

"I'm increasingly gaining appreciation for the role the commission plays ... to be a beacon of stability in an otherwise volatile regulatory and legislative landscape," he said during a panel for NARUC's Committee on Gas. "I understand why people were concerned. You have four new commissioners coming in, and here's [Senate Majority Leader Mitch] McConnell's coal guy. People were concerned that the right decision would get made. I hope now that, in the aftermath, ... that people ... around the country will have confidence that we're going to continue going forward in a fuel-neutral, nonpolitical, reasonable way."

He acknowledged his sympathy for efforts to save coal, given his Kentucky origins.

"The significance of coal-fired generation and the mines, the role they play in the economy, it goes beyond energy and reliability. It really is part of the lifeblood of some communities. ... When the plants close, the mines close, the jobs go away, people are left, their only asset is their homes and oftentimes those homes, they have no value because of the lack of economic opportunity, so it's really, really difficult. Of course, I was sympathetic to the plight of the people in my home part of the country."

FERC Chairman Kevin McIntyre defended the NOPR as "widely misunderstood by many in the industry" but also acknowledged it had not been a priority for the commission.

FERC Chairman Kevin McIntyre | © RTO Insider

"Some of the items we work are actually of our choosing. Others are foisted upon us," he said.

McIntyre acknowledged that state and federal policy "do overlap in some ways" and assured attendees that the commission takes its rulemaking responsibilities "very seriously."

"That makes it hard. One cannot simply say, 'OK, that sounds close enough for us,'" he said. "This country has benefited enormously from robust, competitive markets, so one has to be very careful taking any steps that could have the result of, or even be perceived as, casting aside recognition of those important market benefits."

Commissioner Robert Powelson told attendees at a Committee on Water panel that he expects any proposal from an RTO to have state support. He said "unequivocally" that any proposal "will not garner

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Expert Sees 'Extreme Uptick' in Cyberattacks on Utilities

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"Now that means the cyberattack [modeled] is not a permanent destruction of critical infrastructure," Hempstead added, distinguishing it from the dire scenarios painted by Ted Koppel in his controversial 2015 book "Lights Out." (See Critics: Koppel Doomsday Scenario Ignores Prep.)

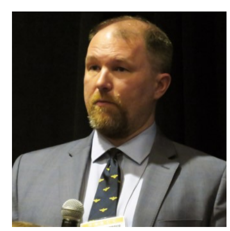
"If Ted Koppel is correct and everything east of the Mississippi is affected by cyber for 18 months, that's outside the bounds of what we're incorporating in our analysis," Hempstead said. "But because utilities are viewed by Moody's as critical infrastructure assets, we believe there will be an extraordinary government intervention to assist the company in putting itself back on track."

Hempstead said Moody's is concerned that the cybersecurity regulations for the utility industry "could create a culture of compliance where the defenses are relaxed because the compliance check boxes are getting checked. That's, we don't think, the right mentality. Cyber risk is an enterprise risk issue and therefore it resides at the board of directors. And we are very encouraged at how many boards of directors in the utility sector are very focused on cyber."

Lee said some of his customers have been reluctant to embrace innovation for fear of being found in violation of reliability standards. Others express concern over how Dragos' subscription-based services will impact their bottom lines. "Right now, one of the biggest pushbacks I get from a lot of my customers across the utility industry is, 'Hey is there any way we cap ex this?'" he said. "We have to figure out how to make sure that the [security effort] that is already moving in the right direction is not hampered by the way we want to do accounting."

GridEx IV

In an earlier presentation, **Bill Lawrence**, director of NERC's Electricity Information Sharing and Analysis Center (E-ISAC), shared lessons learned from GridEx IV exercise in November, which simulated physical and cyberattacks on the electric system. (See Ukraine Attacks, 'Fake News' Color NERC GridEx IV Drill.) E-ISAC works with the Department of Energy and the Electricity Subsector Coordinating Council (ESCC) to inform the industry about physical and cyber threats.



"The scary thing is ... everything we come up with [as an attack scenario] has happened somewhere in the world — about 99% of our entire scenario [has happened]," Lawrence said. "So, things with drones, things with modular malware, things with drains on resources in both computer and physical security."

A public report on GridEx IV is due at end of March. A meeting will be held in November to plan for GridEx V, to be held in 2019.

NARUC Winter Policy Summit

Overheard

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any support if I don't hear from the ... member states ... on the proposal."

Commissioner **Cheryl LaFleur** said, "Of course the views of the states are very important," adding that states can change grid operators if they prefer.

"We don't assign you," she said. "In some regions, the states are not unanimous on one solution, and it does allow the FERC to figure out what's just, reasonable and nondiscriminatory using our own judgment."

Commissioner **Richard Glick** stressed the importance of FERC developing a proposal that actually addresses resilience issues.

"It seems to me ... that some RTOs are suggesting things that don't necessarily [relate] to resilience," he said.

'Fresh Look' at Pipeline Policies

The low cost and abundancy of natural gas also had regulators focused on pipeline infrastructure. Several FERC commissioners discussed McIntyre's plan to review the commission's 1999 policy statement on pipeline approval.

"It has been policy at the FERC not only since 1999, but prior to that, to ensure that no pipeline proposal is approved where there is not a demonstrated need for the project. What has evolved ... is the standard for determining how that is measured and should it continue to evolve," McIntyre said. "It's time for us to dust that off and have a fresh look at it and see what changes, if any, are appropriate to that."

He said FERC should take into account many variables, including environmental concerns and whether the commission should weigh how many contracts with a pipeline have been signed by affiliates of the applicant.

"They're still independent market participants, but is that enough?" he said. "Should the regulator look at the stance in that sort of situation and say, 'That doesn't seem like a valid arms-length measure of pipeline need.'"

Glick said, "The commission's kind of veered away from ... its approach that it had taken in the past toward considering whether there's a need for a pipeline." He said it "seems to be backwards" that the commission has to provide the certificates necessary to access private land to do surveys necessary to determine where pipelines should go.

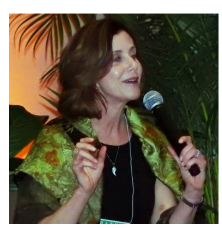
Chatterjee said he's "strongly supportive" of reviewing the policy, is concerned about landowner issues and understands the "complex tension that exists."

Bruce McKay, a senior energy policy director at Dominion Energy who spoke during a panel on pipeline infrastructure, said, "Increasingly, energy policy is being made on a project-by-project basis. The keep-it-in-the-ground movement ... the strategy seems to have shifted to go after pipelines and transportation of energy as a way to change energy policy, as opposed to getting likeminded people elected or persuading those elected into office or in policymaking roles to change policy."

He said that, like highways, the overall capacity of the nation's pipeline system doesn't address local constrictions.

"If you can't get it where you need it when you need it, it becomes a real problem," he said.

Kimberly Harris, CEO of Puget Sound Energy and chair of the American Gas Association's board of directors, noted that the U.S. used 147.1 Bcf of gas on Jan. 1.



"We actually set the all-time record for the output of the natural gas system," she said.

Two-Way Street on PURPA

The commissioners are also interested in reviewing how FERC handles PURPA.

"The question is whether there are steps at the FERC level that will improve the overall playing field of PURPA today," McIntyre said. "The answer is probably 'yes.'"

He indicated several issues to examine, including the project size necessary to be a qualified facility. He said calculation of the avoided-cost rate used for PURPA contracts "is still a very old-fashioned process, determined administratively state by state."

A panel of the Committee on Electricity addressed PURPA issues, arguing that both sides of the issue take advantage of the law for their needs. Advocates for QFs said utilities fight accepting QF energy in favor of their own generation projects, while utilities said QF developers skirt rules to get their projects automatically approved, such as breaking them into smaller-sized units that are automatically accepted.

"The gaming of regulations goes both ways, and you expect that," said **Steve Thomas**, an energy contract manager for paper company Domtar.

PURPA opponents contended the law requires utilities to pay for and accept energy production from QFs even if the utility doesn't need the energy, which can create reliability and operational issues. Proponents say the rule helps QFs crack into markets and that utilities have the tools necessary to avoid paying for energy they don't need.

"The problem is that utilities don't want to ever stop buying," said **Todd Glass**, an attorney representing solar developers. "They want their own generation. They want to continue building. They want to continue buying. They just don't want to buy from QFs. ... What you need to do is hold the utilities to the task of doing avoided cost. If you're going to eliminate the ability for QFs to sell to them, you need to eliminate their own ability to self-build and buy for themselves too. You shouldn't have it both ways: that the utility can get rid of the QFs and then just self-deal."

Kendal Bowman, Duke Energy's senior vice president of regulatory affairs and policy,

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Overheard

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Kendal Bowman | © RTO Insider

said utilities can avoid taking on QF capacity by reducing their avoided-cost rates to zero — but they are still required to buy the energy as it's produced.

"That is 70% of that avoided-cost payment," she said. "Roughly 30% is capacity. The other 70% is energy."

Montana Public Service Commission Vice Chairman **Travis Kavulla** said FERC has interpreted PURPA as requiring states to forecast utilities' avoided-cost rates to set long-term QF contracts.

"This type of administrative pricing essentially requires states to guess at future market prices, allowing QFs to lock in rates that substantially overstate the actual avoided cost as it's revealed in real time," he said. "It's not altogether clear whether a more competitive approach, if states were to embark on it, is legal and comports with FERC's implementing regulations of PURPA. … It's ironic that, in the context of a trendy, happening industry like renewables, we're stuck debating whether or not they should rely on such an arcane crutch like PURPA."

Glass said PURPA hasn't solved the problems of getting small energy projects into large utilities.

"Where there is monopoly ownership of generation, transmission and distribution, the problems remain the same," he said. "Yes, it's an improvement, but [QF resources accounting for] 9% [of generation] is all we've gained in the last 40 years [since PURPA was enacted]. The rest of it is coal, gas, nuclear and the same hydro that existed in 1978. So, yes, we've made improvements, but have we achieved a diverse portfolio yet? I don't think so. We have made strides, don't get me wrong, in diversifying, but we're not there yet."

Thomas saw it both ways. He agreed that cogeneration facilities need the long-term assurance of contracts like PURPA to get approval to make the capital expenditures necessary to build the facilities. But he also supported not paying for more capacity than necessary.

"Certainly any gaming — somebody who can force a utility that doesn't need to buy capacity or energy to buy capacity and energy — is not good," he said. "But we do also support the idea that if I want to bring capacity and energy to your system, that it be fair in price."

He credited PURPA for enabling combined heat and power and waste heat recovery facilities to exist.

"We self-fund our generators. We pay for them out of efficiencies for taking something that was going to go unused and turning it into electricity. I honestly don't know that that ability would have been there without PURPA to try to, for lack of a better word, force utilities to look at allowing these extra generators," he said. "It's hard ... to make the case at a new facility to put in the extreme capital cost for generation if we don't know what the market's going to be or if the market's going to be pulled away from us. And PURPA, even if it's not used, if it's there, it gives us some [assurance] that we can build those assets."

Thomas said the goal is to have it both ways.

"That's what we're looking for: the wisdom to reshape PURPA as needed to make sure customers don't have to buy generation and energy that they don't need, but that when there is a need or when that energy could be fit into a cost curve, that they be allowed to be there," he said.

"They don't like you now, they didn't like you then, they're not going to like you in the future if you're the last man standing."

Todd Glass

Glass objected to Thomas' characterization.

"During the 90s, I represented pulp-paper companies, steel companies, aluminum companies, developing PURPA projects. Utilities hated us. Even more than they hated us, they hate renewables now. To have a revisionist history where utilities have always liked you guys, they don't. They don't like you now, they didn't like you then, they're not going to like you in the future if you're the last man standing," Glass said.

Panelists discussed several ongoing initiatives to revise the rules. NARUC has sent a request to FERC to reconsider how it handles PURPA. U.S. Rep. Tim Walberg (R-Mich.) has also introduced a bill that would allow state regulators to assume some PURPA decision-making currently held by FERC. Kavulla testified on behalf of NARUC in support of the bill before a congressional subcommittee in January. (See House Panel Considers Bills on PURPA, LNG Exports.)

Thomas warned that Walberg's legislation would substantially deter cogeneration projects.

"There's a lot of energy that would go to waste if that were to happen," he said.

— Rory D. Sweeney

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CAISO NEWS

CAISO Board Elects New Leadership

Board Briefed on Roadmap, Hears RMR Critics

By Jason Fordney

The CAISO Board of Governors last week enacted new governance policies and named Governor David Olsen as chairman. It also reviewed the ISO's policy roadmap for 2018.

In a teleconferenced meeting Thursday, the board enacted a new process whereby governors will hold yearly elections for chair. The five-member board voted to replace sitting Chair Richard Maullin with Olsen, who was originally appointed to the board in 2012 by Gov. Jerry Brown.

Governor Angelina Galiteva said that with CAISO involved in more regional matters and the Western Energy Imbalance Market (EIM), the board felt members should have the opportunity to participate as chairs and share some of the growing workload. The board went through an analysis to study best practices, she said.

"This is something we thought over and talked about for quite a while," Galiteva said. The board elected her to the newly created position of vice chair, nominated by Governor Mark Ferron and seconded by Governor Ashutosh Bhagwat.

"We are entering a period where there could be some rapid change we are part of or instrumental for," Maullin said, as other board members thanked him for his service in his role. Maullin's term on the board ended Dec. 31, and he said remaining on the board depends on the California State Senate, which confirmed him as chair in July 2015. He was reappointed by Brown in January 2015.

Cook Briefs Board on 2018 Roadmap

CAISO Director of Market and Infrastructure Policy Greg Cook briefed the board on the 2018 Policy Initiatives Roadmap and Annual Plan, saying the presentation to the board represents the final step in the implementation process.

In January, Cook briefed the EIM Governing Body on the plan, which includes a proposal to extend the ISO's day-ahead market to the EIM. (See *EIM Body Tables Nominating Process Changes*.) This will create regional benefits, including day-ahead unit commitment and scheduling, across the EIM footprint, improving efficiency and integration of renewables, Cook said. (See *CAISO Plan Extends Day-Ahead Market to EIM*.) Each balancing authority area would retain reliability responsibility, and states would retain control over integrated resource planning. Transmission planning and investment remains with each BAA and local regulatory authority.

Cook shared some of the tasks associated with the day-ahead market extension, including the alignment of transmission access charge paradigms to ensure EIM entities recover transmission costs consistent with the existing bilateral network, and consistent billing determinants across the day-ahead market footprint for market efficiency. There will also be distribution of congestion rents collected through the day-ahead market and a day-ahead resource sufficiency evaluation, among other requirements.

Keith Casey, the ISO's vice president of market and infrastructure development, told the board that implementing the day-ahead across the EIM will provide additional benefits, but it "certainly will fall short of the full benefits we would get with full participation under a regional construct." These would include efficiency of a single balancing authority over a larger footprint, as well as transmission planning and resource adequacy benefits.

"We believe it has important benefits … but I do want to stress it will fall short of the full integration benefits," Casey said.

PG&E Continues Criticism of RMRs

During a public comment period, Eric Eisenman, director of ISO relations and FERC policy for Pacific Gas and Electric, told the board that PG&E has no issue with anything in the roadmap but that addressing the increasing use of reliability-must-run designations (RMRs) and the capacity procurement mechanism (CPM) is the utility's "highest priority." He reminded the board of the "robust discussion" it had over RMRs at its November meeting when the designation of the gas-fired Metcalf Energy Center was approved. (See *Board Decisions Highlight Market Problems*.)

"PG&E continues to be very concerned about a slew of RMRs for 2019 that would be designated later this year," Eisenman said. "But at this point, we just don't know what is going to happen." He urged CAISO to implement more extensive "Phase 2" changes in its RMR/CPM initiative in time for 2019 designations. The ISO has indicated it only intends to address must-offer requirements for RMR and CPM units in that time frame.

Casey said the ISO is looking at transmission alternatives to prevent situations that might otherwise lead to RMRs, including working with PG&E to address "low-hanging, fast upgrades" in the subarea where the Metcalf plant sits. The improvements would alleviate about 600 MW of local capacity requirements and are included in a transmission plan due to be finalized in March, he said.

"There is much we can do — we have a great deal of flexibility with the transmission plans to do those types of studies," but it would be challenging to complete the improvements by fall 2019, he said.

"We share PG&E's urgency about getting after these RMR reforms," Casey said.

CAISO is in the midst of developing a package of enhancements to the RMR/CPM process, which is proving to be a contentious proposal among market stakeholders. (See *CAISO, Stakeholders Debate RMR Revisions*.)

Newly elected CAISO Board Vice Chair Angelina Galiteva and Governor Mark Ferron in November 2017 | *© RTO Insider*

CAISO NEWS

FERC Approves EIM Changes, Western Measures

By Jason Fordney

FERC on Thursday approved a package of modifications to improve market efficiency developed by CAISO for the Western Energy Imbalance Market (EIM). It also issued several other decisions related to Western states and energy markets.

The commission said the EIM measures would improve efficiency by automating manual processes, providing greater transparency into bilateral transactions and enabling increased participation in both the EIM and CAISO.

The approved changes include automated matching of import/export schedule changes between resources inside and outside the EIM, as well as the ability to automate changes to mirror system resources at intertie scheduling points between CAISO and an EIM entity (ER18-461).

"We find that the automated matching and the automatic mirroring functionalities will result in more efficient EIM market outcomes by automating manual processes that are prone to errors and better maintain balance between resources and load following intertie schedule changes," FERC said.

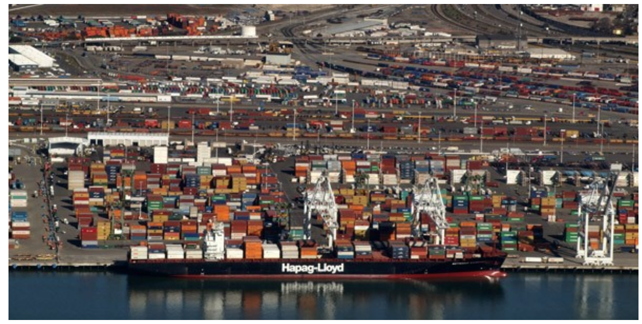
The EIM Governing Body approved the package of changes in November, after CAISO had scaled down the initiative based on consultations with stakeholders. (See *EIM Governing Body Approves 'Consolidated' Initiatives*.) The changes also facilitate bilateral settlements and improve the market's modeling accuracy by expanding the functions of non-generator resources.

CAISO had requested approval of the measures by Feb. 15 to allow for the participation of Powerex and Idaho Power in the EIM on April 4.

Deseret Earns MBR Authority

The commission last week also approved Deseret Generation & Transmission Co-operative's updated market power analysis for the Northwest region, granting the utility market-based rate authority effective Sept. 12, 2016. Utah-based Deseret became a public utility in 1996 after paying off its debt related to rural utility service (ER16-2186).

Deseret owns the 458-MW Bonanza coal-fired plant and a 25% interest in the 430-MW Hunter 2 coal-fired unit, both in the PacifiCorp balancing authority area.


Port of Oakland

FERC Approves PG&E/ Port of Oakland Agreement

The commission also approved an interconnection agreement between Pacific Gas and Electric and the Port of Oakland but suspended the agreement and subjected it to hearing and settlement judge procedures (ER17-2536).

The port acts a municipal electricity supplier that serves customers located at the Oakland International Airport, which it owns and operates, using PG&E's transmission and distribution facilities.

Last year, the port submitted an application to convert its Cuthbertson substation from retail service to wholesale interconnection service under PG&E's transmission owner tariff, but PG&E identified an issue with the tariff based on the substation's power factor, which it said has to be resolved before it can provide wholesale service.

The port contends that PG&E's sales for resale to it are subject to FERC jurisdiction and that it is concerned about provisions in the interconnection agreement referring to matters under the jurisdiction of the California Public Utilities Commission. The port argues that PG&E is attempting to "improperly impose" CPUC-jurisdictional exit fees on it and protests language describing the change to wholesale service as a notice of departure from PG&E, subjecting the port to departing load fees.

The port also contests that certain aspects of the agreement are unreasonable and unduly discriminatory compared with other PG&E interconnection agreements.

FERC set a public hearing subject to settlement procedures to be held within 15 days.

GridLiance Rehearing Request Rejected

FERC rejected GridLiance West's rehearing request contending the commission erred when it failed to approve the company's proposed use of an actual capital structure related to incentive rates for facilities it sought to acquire from Valley Electric Transmission Association (ER17-706). GridLiance West said the proposed capital structure was comparable to similarly situated transmission companies.

In its order denying rehearing, the commission said it made no final determination regarding the proposed capital structure but "found that its preliminary analysis indicated that the proposed TO Tariff had not been shown to be just and reasonable and raised issues of material fact that could not be resolved on the record before the commission."

Idaho Commission Complaint Headed to Court?

FERC also declined to act on a petition for enforcement filed by Franklin Energy Storage against the Idaho Public Utilities Commission (EL18-50, *et al.*). The company argued the state commission had improperly classified its energy storage facilities as solar qualifying facilities, preventing them from being eligible for the PUC's stated electricity rate under the Public Utility Regulatory Policies Act. The rate is available to non-wind and non-solar QFs of an average capacity of 10 MW or less.

The decision will allow the company to bring an enforcement action against the Idaho commission in the appropriate court, FERC said.

CAISO NEWS

CAISO Developers Urge Interconnection Changes

By Jason Fordney

Some energy resource developers in California say CAISO needs to change its interconnection rules to prevent financially unviable projects from lingering in the queue and affecting more sound projects.

CAISO's annual Interconnection Process Enhancements (IPE) process is becoming increasingly complex as the state's generation mix changes, with renewables and storage comprising the vast majority of projects currently in the queue. The ISO outlined its 2018 IPE in an issue paper last month. (See *CAISO Launches Interconnection Initiative*.)

As part of the initiative, CAISO asked for comment on whether it should alter its transmission plan deliverability (TPD) allocation, which establishes the amount of additional transmission capacity needed for projects to achieve deliverability and determines generators' cost responsibility for network upgrades costs. Projects allocated sufficient TPD receive reimbursement for their upgrades. CAISO uses a point system to allocate TPD based on project status, including the status of project financing, power purchase agreements, regulatory approvals, land acquisition and other factors.

CAISO's current process provides interconnection customers with two annual opportunities for earning TPD allocations: following Phase II interconnection studies, and after one year of parking in the queue. Under revisions filed with FERC, which the ISO says are likely to be approved, a third annual opportunity for a TPD allocation will be made available to interconnection customers following a second year of parking. Projects that don't qualify for a TPD allocation following the three opportunities must convert to energy-only status — making them ineligible for resource adequacy payments — or withdraw from the queue.

In its comments to CAISO, Southern California Edison said it opposes allowing projects to remain in the queue indefinitely and have endless opportunities to apply for deliverability status.

"Such projects remaining in the queue open-endedly without making progress towards their commercial operation negatively affect other active projects," the company said.

SCE said projects not allocated TPD by the end of the second parking period should be required to execute the agreement and proceed as energy-only or be suspended, allowing for a three-year period during which they retain priority for TPD allocation. Two parking periods and a three-year suspension should be adequate, the utility said.

Differing Opinions on TPD Allocation Changes

Utility-scale developer First Solar said that forcing projects into "energy-only" status and large forfeiture amounts that become due if a project withdraws might incite developers to choose energy-only status rather than depart the queue. The company said the issue is compounded by a lack of transparency of available deliverability at interconnection points on the CAISO grid.

"Deliverability is critical for marketing a project, as energy-only projects currently are less appealing due to their lack of resource adequacy attribute and are therefore less competitive in procurement," First Solar said. "We ask the CAISO to address several issues that prevent interconnection customers from being allocated or retaining deliverability, as well as issues that have impacts on others in the queue."

But the state's Office of Ratepayer Advocates said it did not support changes to the current TPD allocation process that allows three opportunities for TPD allocation, rather than allowing projects to remain in the queue indefinitely.

"Changes in the queue procedures should only be considered for resources that meet project area needs, support state resource targets or CAISO-controlled grid needs, such as resources that can respond to grid demands throughout the day and/or provide additional services in addition to energy," the office said.

The California Wind Energy Association said that with the third allocation option on file at FERC, "there is no need to tinker with the TPD allocation process. We suggest that this IPE element be tabled."

Independent transmission company ITC Holdings said it supports inclusion of the possible TPD changes in the scope of the 2018 IPE stakeholder initiative as part of its "broader support" for studying the impacts of allowing projects with potentially limited commercial viability to remain in the queue and seek TPD allocation.

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CAISO NEWS

CAISO Urged to Take Slower CRR Approach

By Jason Fordney

FOLSOM, Calif. — CAISO is moving ahead with major modifications to its congestion revenue rights (CRR) auction even as some stakeholders urge a deeper look into the possible detrimental effects of the plan before it goes to FERC.

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CAISO defended its approach during a Feb. 13 forum on the CRR process. Some commenters are saying the ISO is taking an overly simplistic view of the issue: whether the CRR auction is a legitimate hedging mechanism or a process that forces ratepayers to become unwilling participants in losing transactions.

CAISO's Department of Market Monitoring has become increasingly outspoken about what it calls auction "payment deficiencies" of more than $500 million — the difference between auction proceeds and payouts, which are based on day-ahead market congestion. But some market participants are protesting that the ISO is ignoring other benefits from the transactions. The debate over financial transmission rights is also occurring in other ISOs and RTOs. (See *Market Monitors Bring FTR Complaints to Congress*.)

CAISO discussed reforms throughout last year and unveiled its initial reform proposal at the beginning of this month. (See *CAISO Overhauling CRR Auctions*.)

The ISO intends to eventually restrict CRR transactions to only those needed for physical transfer of energy, and limit CRR source and sink pairs to nodes between generators and interties, as well as between trading hubs, loads and interties. It has also proposed to decrease the amount of system capacity released in the CRR auction process from 60% to 40% in the long-term allocation, and 75% to 45% for the annual allocation and auction process — a move intended to reduce overselling of transmission capacity. The ISO would also eliminate disclosure of certain modeling information and align existing outage reporting rules with the annual CRR process.

Track 1 of the effort consists of measures to be put in place for the 2018 auction process this summer, slated for March approval by the Board of Governors. Track 2 will include more significant changes, targeted for board approval sometime in the middle of the year, CAISO Market Design Manager Brad Cooper said in a presentation.

Kolby Kettler, of energy and commodities trader Vitol, has questioned the proposal since it was introduced. On Feb. 13, he said the plan could introduce detrimental effects and new risks that CAISO has not considered.

"Other ISOs have also gone down this avenue, looking at removing locations, and have backtracked" because of revenue loss to the market, he said. He urged CAISO to focus on "fixing the model, and not focus on removing what could be a legitimate hedging activity or valuing congestion."

"We are working to try and quantify the benefits of auction CRRs to the broader market," Cooper replied, adding that "this isn't the net effect … because CRRs have a benefit to the bilateral market."

Speaking for the Western Power Trading Forum, Ellen Wolfe contended that CAISO was operating from a narrow viewpoint. She said the ISO has "narrowed in on the premise of the purpose of the CRRs being this physical hedge," but that certain hedges might be beneficial for physical supply in ways the ISO is not considering.

"You build these proposals based on that particular premise — it presents a very narrow viewpoint of the world — and present anything outside of that viewpoint as not legitimate," she said. "It is at least beneficial … to acknowledge that not everybody agrees with your premise." Previously, there was never a sense that CRRs should be made available only to generators serving a load, she said.

"We are doing all we can to understand the uses," Cooper said, but the auction revenues are far short of what CRRs are paying. "Sure, we would be eliminating combinations to allow for every type of conceivable hedging opportunity," but "I think we are striking a reasonable balance," he added.

CAISO is taking comment on its CRR proposal through Feb. 28.

CAISO Developers Urge Interconnection Changes

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ITC also recommended the initiative further examine "how identified impacts of an interconnection request on neighboring systems are coordinated and mitigated" to "consider additional clarifications to affected system practices."

The company pointed to FERC's recent order on a complaint by the Environmental Defense Fund regarding MISO, PJM and SPP affected system studies. Earlier this month, the commission ordered technical conference after finding the RTOs' tariffs and joint operating agreement do not fully explain the guidelines and timelines that the RTOs use to coordinate with other affected systems during the interconnection process. (See *FERC Orders Review of PJM, MISO, SPP Generator Studies*.)

As of Jan. 1, the ISO's interconnection queue contained about 43,000 MW of proposed generation, including about 28,000 MW of renewables, 12,000 MW of storage and 2,800 MW of other resources, documents show.

ERCOT NEWS

PUCT Nears Approval on LP&L Move to ERCOT

By Tom Kleckner

AUSTIN, Texas — The Public Utility Commission of Texas last week hinted it may be near a decision on Lubbock Power & Light's proposal to move 470 MW of its load from SPP to ERCOT.

During their Feb. 15 open meeting, the regulators asked an administrative law judge to rule on some remaining questions and submit a final order before their March 8 meeting (Docket No. 47576).

Chair DeAnn Walker suggested the ALJ avoid a detailed discussion of exit fees and save that for a staff rulemaking. LP&L committed to paying an exit fee in a settlement agreement with intervenors, but as Walker pointed out, the utility has also chosen to participate in ERCOT's competitive retail market.

"If they make that choice, they're not going to be able to leave" ERCOT's competitive market, she said.

Walker said the order should assign LP&L and Sharyland Utilities — which has proposed a $247.5 million, 345-kV project that overlaps with the facilities necessary to integrate Lubbock's load into ERCOT — to coordinate the respective parts of the system for which each would be responsible.

"If they're unable to agree, they will have to file a proceeding here," Walker said.

LP&L officials, who had expected a final order, were nonetheless thrilled with the PUC's action. In a statement, David McCalla, LP&L's director of electric utilities, called it "the most important milestone to date in our case to join ERCOT."

Lubbock's power needs are currently met through two long-term contracts with Southwestern Public Service, one of which — 470 of 600 MW — expires in June 2021. LP&L says moving from SPP to ERCOT and allowing retail competition will give its customers access to a "diversified portfolio of reliable and affordable Texas power for generations to come."

The utility reached a settlement agreement with SPS, PUC staff, the Office of Public Utility Counsel and other consumer groups last month. The Lubbock City Council and LP&L's board of directors approved the settlement, which the utility filed with the PUC on Feb. 8. (See *Lubbock Council, Utility Board Approve LP&L Settlement*.)

LP&L has agreed to pay $22 million annually over five years to compensate ERCOT's transmission customers for additional infrastructure costs, and to also make a one-time $24 million payment to SPS for previous infrastructure costs.

While thanking everyone for their efforts in reaching a settlement, Walker couldn't resist needling LP&L attorneys Lambeth Townsend and Chris Brewster. "It would have been nice if it had been before the hearing," she said, referring to the commission's two-day hearing in January. (See *Texas Regulators Noncommittal After LP&L Hearings*.)

The commissioners discussed the need for a rulemaking on future transfers. Rayburn Country Electric Cooperative, which sits on the ERCOT-SPP seam in East Texas, has proposed transferring load and transmission facilities into ERCOT, while Walker alluded to holding a recent discussion about another transfer "that's on the horizon." (See "ERCOT, SPP Agree to Rayburn Country Migration Studies," *Public Utility Commission of Texas Briefs: Aug. 31, 2017*.)

"I personally don't think we learned enough with this [transfer] to get specific," Commissioner Arthur D'Andrea said in agreeing to the need for the rulemaking. "I wonder if we can't get into the weeds on some of the rules."

The commission also asked staff to open a project within the docket that would require LP&L to file quarterly updates on the transition's status.

ERCOT NEWS

Texas PUC Briefs

Commissioners Delay Action on Removing RUCs from ORDC

AUSTIN, Texas — The Public Utility Commission of Texas postponed until March a decision on whether to remove reliability unit commitments (RUCs) from ERCOT's operating reserve demand curve (ORDC), which creates a real-time price adder to reflect the value of available reserves.

The delay will allow the commission to gather more feedback from ERCOT on the effects of removing RUCs before heading into the summer months. The commissioners are reluctant to make additional changes that may affect prices, following a recent wave of coal retirements that halved the ISO's planning reserve margin to 9.3%.

Staff issued a memo Feb. 8 that recommended removing RUC capacity from the ORDC "to ensure that out-of-market commitments do not impede accurate price formation during scarcity." (See *ERCOT, Regulators Discuss Need for Pricing Rule Changes*.)

"We are prepared for what the summer is going to bring, which is high prices," Commissioner Brandy Marty Marquez said. "The question we've got to ask ourselves is what are the signals we want to send going into the summer? We're going into a summer where people are going to be potentially paying a lot more. Will we make changes that have another factor of costs layered onto that?"

Walker checked her understanding of ERCOT's RUC process with Kenan Ogelman, the ISO's vice president of commercial operations. He told her that ERCOT seldom issues RUCs during the summer, and that its operators continue to minimize their use.

"We might RUC something for capacity initially, but it's also ultimately the solution for a local issue," Ogelman said. "They tend to intertwine somewhat, so we're looking at how we might differentiate those."

Walker said she didn't want to make any "big changes" going into the summer but also said she believes removing RUCs from the ORDC is the "right decision." Ogelman responded that the ISO could provide further information to the PUC for its next meeting and still gain approval from its board of directors by July.

That gave comfort to the commissioners, who seem to be leaning toward removing RUCs from the ORDC. Whether it happens before this summer or the next, remains to be seen.

"I think it's the right policy … but we're going into a situation that's new," Marquez said. "Any changes we make at this point … will have an impact on ratepayers. We just don't know exactly what that's going to be. Do we do something at this point that turns up the heat on this, or do we let ourselves go through the summer, and then have more information on it?"

"This is a real opportunity to see how the ORDC works, and we should take it," Commissioner Arthur D'Andrea said. "That said, removing the RUC from the ORDC makes sense to me, but not if the retail electric providers start screaming bloody murder. My understanding is this could get done rather painlessly."

Catherine Webking, representing the Texas Energy Association for Marketers, told the commissioners her group would want to see further "quantification" from ERCOT before their next meeting.

"We would not be screaming bloody murder," she said, "but we do think it violates the concept of giving time to make adequate changes in [power] contracts."

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Utilities Propose Mechanism to Pass on Tax Savings

The PUC continues to deal with the fallout from the reduction in the federal income tax rate and how those savings should be passed on to consumers.

Staff told the commissioners they have been meeting with investor-owned electric utilities, who have all proposed using any combination of three ratemaking mechanisms to share their tax savings: revising their interim transmission cost-of-service (TCOS) and/or their distribution cost recovery factor (DCRF), or by using a credit rider adjustment.

"All companies have indicated they will use one or more of those methods, and all plan to do it in a very timely manner," reported staff's Darryl Tietjen. By rule, utilities must file their requested DCRFs by April 1.

Tietjen noted Houston's CenterPoint Energy had already filed a letter detailing terms of a settlement it had reached with staff and other parties. CenterPoint committed to a series of filings that will include revisions to its TCOS, a DCRF application and a base rate case, to be filed no later than April 2019.

Texas Sen. Kelly Hancock (R), chair of the Business and Commerce Committee, has also filed a letter with the commission asking all retail electric providers (REPs) to make a public commitment that they will pass tax savings on to their consumers.

"Any deviation from that practice would result in legislative action to clarify the regulatory scope of the commission" during the Legislature's 2019 session, Hancock warned.

Walker asked staff to work with the REPs and "see if there's some way to accomplish

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ERCOT NEWS

Sempra Moves Closer to Securing Oncor Acquisition

By Tom Kleckner

AUSTIN, Texas — Sempra Energy's proposed $9.45 billion acquisition of Energy Future Holdings and its interest in Oncor took a major step toward reality Thursday before the Public Utility Commission of Texas.

The commission canceled a hearing on the merits of the deal scheduled for next week and directed staff to prepare a proposed order in the proceeding (Docket No. 47675). The PUC is expected to revisit the issue during its next open meeting on March 8.

EFH, which declared bankruptcy in 2014, holds an indirect 80% interest in Oncor, once its crown jewel but now the lone business remaining in its portfolio. Hunt Consolidated, NextEra Energy and Berkshire Hathaway Energy have all come up short in previous attempts to acquire Oncor, the largest electric utility in Texas.

"The fourth time's the charm!" said an onlooker to a smiling Oncor CEO Bob Shapard, clapping him on the shoulder as he left the PUC's hearing room.

Shapard and General Counsel Allen Nye, who will both retain positions on the post-acquisition board of directors as chairman and CEO, respectively, were singled out for praise by PUC Chair DeAnn Walker. She thanked them for their work in what she said was a "very painful process" for them.

Walker also apologized to a large contingent of Sempra representatives, which included CEO Debra Reed, for making the long trip from California for a discussion that took less than two minutes. "Come back and see us anytime," she said.

Walker acknowledged the work of both parties involved in the transaction. San Diego-based Sempra and Oncor have agreed to a list of commitments in settling with all 10 parties that have intervened in the case, rendering a hearing moot. (See *Sempra, Oncor Reach Agreement with Texas Intervenors*.)

"The unanimous settlement agreement is incredibly positive and demonstrates support for the proposed Sempra transaction from all parties," Oncor spokesman Geoff Bailey said in an email to *RTO Insider*. "We look forward to reviewing the proposed order from the commission and answering any further questions that they may have."

Sempra said it was pleased with Thursday's developments. The company announced its intentions to acquire EFH last August and received approval from the U.S. Bankruptcy Court for the District of Delaware in September. FERC gave its approval for the acquisition in December, but the transaction remains subject to the PUC's approval and that of the bankruptcy court.

"If approved by the commission, we will have the opportunity to potentially bring this long ordeal to a close, and Texas will get a terrific partner in Sempra," Bailey said.

Texas PUC Briefs

Continued from page 12

what Sen. Hancock has asked us to look at."

The commissioners also amended a previous order on the subject, deleting a reference to carrying changes on the balance of excess accumulated deferred federal income taxes (Docket No. 47945).

Staff Opens Battery-Storage Rulemaking

Saying it did not have "sufficient information" to rule on American Electric Power's request to connect a pair of utility-scale battery facilities to the ERCOT grid, the PUC asked staff to open a project that addresses "necessary policy issues" and develops an "appropriate regulatory structure" through a future rulemaking (Docket No. 46368).

"Only after facts are fully developed will the commission be in a position to resolve relevant policy issues and design the appropriate regulatory framework with proper

ERCOT's Kenan Ogelman addresses the PUC. | © *RTO Insider*

standards," the commissioners said in their order. New rules are necessary "to define the appropriate manner in which energy storage devices are used before the use of energy storage devices can move forward."

AEP had proposed installing separate 1-MW and 50-kW battery facilities in two rural Texas areas, setting them to automatically discharge during an outage or to serve additional loads. It has proposed the energy be accounted for as "unaccounted-for energy (UFE)," which ERCOT defines as the difference between the system's total generation supply and the total system load plus losses.

Consumer organizations and market participants both opposed AEP's request, arguing that allowing the assets to be included in its regulatory base would harm competition.

(See *PUCT Considering Rulemaking over AEP Battery Proposal*.)

Commission Approves Investment Firm's Acquisition of Calpine

The commission, as part of its consent agenda, approved Calpine's request to be acquired by private investment firm Energy Capital Partners (ECP) in a $5.6 billion deal (Docket No. 47607).

Commission staff found no market power concerns, saying Calpine and its subsidiaries will own or control about 12 GW of ERCOT's installed capacity upon the transaction's consummation, or almost 13% of ERCOT's total — below the 20% cap.

Under the merger agreement's terms, VoltSub, an ECP subsidiary, will merge with Calpine, which will continue as the surviving entity.

Calpine announced it was going private last August. New York regulators and Calpine stockholders have also approved the transaction, which is targeted to close in the first quarter of 2018. (See *Calpine Going Private in $5.6B Deal*.)

— Tom Kleckner

ISO-NE NEWS

ISO-NE Defends CASPR Against Protests

By Michael Kuser

ISO-NE on Thursday defended its proposed two-stage capacity auction, responding to criticism by its External Market Monitor and others.

In its Feb. 13 response to protests, the RTO asked the commission to approve its Competitive Auctions with Sponsored Policy Resources (CASPR) program, saying the Monitor's "proposed cure would be worse than the disease" (ER18-619). Monitor David Patton filed a protest Jan. 30 saying that he supports "the objective and approach" of CASPR but that the RTO's proposal has a "critical design flaw" that will result in "inefficient investment and retirement decisions and over the long term … raise costs substantially to New England's customers."

Also filing protests in response to the Jan. 8 CASPR filing were Massachusetts Attorney General Maura Healey; municipal utilities (New England Consumer-Owned Systems); Connecticut; the Natural Gas Supply Association; a coalition of environmental groups (Clean Energy Advocates); the New England Power Generators Association; and several merchant generators. (See *CASPR Filing Draws Stakeholder Support, Protests*.)

The CASPR proposal grew out of the New England Power Pool's Integrating Markets and Public Policy (IMAPP) initiative, launched in August 2016 to address state regulators' concerns about ratepayer costs associated with policy-driven resources and generators' fears that out-of-market procurements of renewable generation would suppress capacity prices.

Under ISO-NE's proposal, it would clear the Forward Capacity Auction as it does today, applying the minimum offer price rule (MOPR) to new capacity offers to prevent price suppression. In the second Substitution Auction (SA), generators with retirement bids that cleared in the primary auction would transfer their obligations to subsidized new resources that did not clear because of the MOPR. The proposal would phase out the current Renewable Technology Resource (RTR) exemption, which has allowed ISO-NE to clear 200 MW of renewable generation in its capacity auction annually (to a maximum of 600 MW) without regard for the MOPR.

Bad Cure

ISO-NE said it prohibited new conventional resources from participating in the secondary auction "to protect the Forward Capacity Market's ability to guide competitive and cost-effective entry and exit decisions to maintain resource adequacy."

But Patton's Jan. 30 filing said the exclusion of new conventional resources from the SA will cause "new resources to clear and enter when they are not economic or needed and existing resources to retire that are economic to continue operating and whose costs of remaining in operation (i.e., going forward costs) are much lower than the entry costs of new resources that are entering."

Patton would allow new conventional resources to clear through the SA "so they may be efficiently displaced by the sponsored resources."

"This was a component of the ISO's original proposal, but it decided to alter its proposal by excluding the new conventional resources from the Substitution Auction," Patton wrote. "By doing this, the supply and demand (and prices) that will determine when a new conventional resource enters will ignore supply from the sponsored resources."

The RTO retorted that "the EMM's proposed cure would be worse than the disease" by creating "more, and more significant, problems than the overbuild problem it seeks to fix."

One such problem would be fictitious entry, in which developers with no intention of building generation enter the FCA just to secure the severance payment in the second auction. The EMM's fix? New conventional resources that are displaced by a sponsored resource would receive no payment.

The RTO said that could scare off new competitive generation, resulting in high capacity clearing prices — the "price blowout problem."

Patton said that fear is "misplaced."

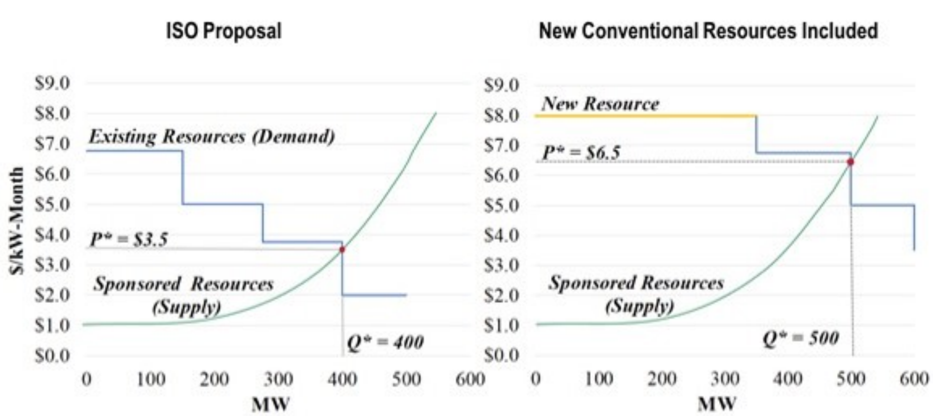
"The risk described by the ISO is a risk that is common to all investment decisions and is efficient for the investor to consider in making its investment decision. Any time new resources are entering the market, whether they are sponsored resources or competing conventional resources, this will reduce the expected profitability and increase the risk to subsequent investment," he wrote.

The EMM would modify the MOPR applied to sponsored resources in the primary FCA so that they can clear at a moderate price, potentially replacing the market-based clearing price with an administratively determined one.

"In addition to its complexity, this multilayered solution is both unfair and ineffective," the RTO said.

Impossible to Win?

"In this situation, the conventional new re-



ISO-NE's External Market Monitor included this example in its protest, saying excluding new conventional resources from the Substitution Auction (left) would clear only 400 MW of sponsored resources, with three existing resources retiring and sponsored resources foregoing $31.2 million in capacity payments. Under the Monitor's proposal (right) 500 MW of sponsored resources would clear and only one plant would retire. Sponsored resources' foregone capacity payments would total only $2.7 million. | *Potomac Economics*

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ISO-NE Defends CASPR

Continued from page 14

source has responded to the market's price signal and succeeded in securing a capacity supply obligation (CSO) because it was willing to sell its capacity in New England at the primary auction's clearing price," the RTO said. "To strip such a resource of its award without compensation would alter the meaning of the clearing price, as a high price no longer would serve its fundamental purpose as a market signal to encourage commercial investment."

The EMM's proposal makes it impossible to "win" an auction, and the outcome differs fundamentally from "the outcome of a normal competitive auction in which an investor fails to clear because its offer price exceeds the market's clearing price," the RTO said.

ISO-NE also objected to the EMM's proposed "price-setting by administrative dictate," which it found "problematic, both practically and philosophically."

Practically, the EMM methodology would create reliance on a predetermined estimate that may or may not reflect the true net cost of new entry (CONE), and "to the extent that number is wrong, FCM's clearing price may be inflated or deflated," the RTO said.

Philosophically, the EMM's proposal would result in an outcome largely dependent on administrative parameters. The outcome, like that of the RTR exemption that CASPR seeks to replace, "ameliorates system overbuild but undermines the competitiveness of capacity prices," ISO-NE concluded.

Applying the Monitor's proposal to FCA 12 would have resulted in total costs of $4.15 billion, an increase of $908 million, or 28%, the RTO said.

"There can be no perfect solution that completely meets the objectives to maintain competitive pricing and accommodate state-sponsored resources," ISO-NE said. "When required to trade between these competing objectives, the ISO prioritizes competitive prices."

RTR Exemption

The RTO also defended its proposal to phase out the RTR exemption, calling it a "blunt instrument."

The conditions that made the RTR exemption just and reasonable upon its adoption will no longer exist going forward, the RTO said: "Instead, load growth has slowed, the region has excess capacity, and, most significantly, the states have announced plans to contract for substantial amounts of sponsored capacity."

NextEra Energy and NRG Energy insisted that the commission eliminate the RTR exemption immediately, saying it suppresses prices. CASPR would phase out the exemption by allowing the exempt megawatts that have accrued in earlier auctions — currently 481 MW — to be used over the coming three years through FCA 15.

NextEra argued that the three-year phase-out made no sense because the conditions that supported the exemption no longer exist. The RTO answered that a measured transition was necessary to maintain investor confidence and lower costs over the long term. It noted that the commission has accepted similar transition mechanisms in other capacity market proceedings.

Attorney General Healey opposed CASPR as not allowing "for any regular or reliable integration of sponsored policy resources" into the FCM. She recommended a mechanism like the "backstop" proposed by the New England States Committee on Electricity, which would guarantee entry of up to 200 MW of sponsored policy resources annually regardless of whether they were matched by retirements.

She also suggested the commission could remand the proposal to the RTO with an order to reinstate the RTR exemption.

The RTO said that, given current market conditions, a 200-MW RTR exemption would depress FCA clearing prices by up to 87 cents/kW-month. Continuing the RTR exemption or adding a backstop would undermine CASPR "because no sponsored policy resource would elect to sell capacity at a low price in the Substitution Auction when it could instead receive the higher primary auction price through the exemption," ISO-NE said.

ISO-NE NEWS

FERC Grants Deadline Waiver for New Hampshire Generator

By Michael Kuser

FERC on Thursday granted a waiver request from Public Service Company of New Hampshire (PSNH), allowing ISO-NE to accept its restoration plan for the Lost Nation generating unit, which the company submitted one business day after the deadline under the RTO's Tariff (ER18-465).

Eversource Energy, PSNH's parent company, in January completed the sale of its fossil-fuel generation units in New Hampshire to Granite Shore Power.

On Oct. 20, ISO-NE flagged the oil-fired combustion turbine in Groveton, N.H., for having a significant decrease in capacity below its cleared capacity supply obligation (CSO) of 13.97 MW for the RTO's 2018-2019 capacity commitment period.

Under the rules governing the RTO's annual reconfiguration auctions, Lost Nation had 10 business days to either purchase additional capacity to replace the shortfall or submit a restoration plan showing how it would be able to meet its obligation.

Lost Nation power plant | *Eversource*

PSNH said the decrease in capacity occurred because a summer seasonal claimed capability audit was not performed. An Eversource employee intended to file a restoration plan showing that Lost Nation was dispatched four days in September 2017 and thus should be capable of supplying output to meet its awarded CSO.

The utility said that two events caused the delay in submitting the restoration plan.

First, the mother of the employee charged with submitting the plan died on Oct. 29, 2017, while the plan was out for review. Then, after a strong storm tore through the state on Oct. 30, the employee was called to storm duty and performed three consecutive 13-hour shifts until being released on Nov. 2. He was then given leave to prepare for his mother's Nov. 4 memorial service.

The combination of events distracted the employee from submitting the restoration plan by the close of the Friday, Nov. 3 submission window; he submitted the plan the morning of Monday, Nov. 6. The RTO said it could not unilaterally waive the Tariff-imposed deadline.

In its Feb. 15 decision, the commission found that "PSNH acted in good faith by submitting the restoration plan as soon as possible after it discovered the omission." The commission also noted that PSNH's waiver request was uncontested.

ISO-NE NEWS

ISO-NE Outlook Highlights Fuel Security, Renewables

By Michael Kuser

ISO-NE's 2018 Regional Electricity Outlook released Wednesday reiterates concerns about fuel security that were detailed in a separate report published by the RTO last month.

In a joint preface to the outlook, ISO-NE CEO Gordon van Welie and Board of Directors Chair Philip Shapiro said "the biggest challenge to the reliability of the grid is the lack of fuel infrastructure to supply the fleet of natural-gas-fired generators."

The RTO's Operational Fuel-Security Analysis examined 23 fuel-mix scenarios and concluded that power shortages because of inadequate fuel would occur in 19 of them by winter 2024/25, which would require emergency actions such as voluntary energy conservation and involuntary load shedding. (See *Report: Fuel Security Key Risk for New England Grid*.)

Shapiro and van Welie also cited further emission restrictions on oil-fired generators "and the reality that older oil and nuclear generators are becoming less economically competitive and may retire before the region has added sufficient new energy sources to replace them."

The outlook pointed to the recent cold snap that hit the region from Dec. 26 to Jan. 7, during which "constrained pipeline capacity resulted in substantially higher natural gas and wholesale electricity prices, leading to less expensive oil and coal power plants operating instead of the usually competitive natural gas-fired generation."

Oil supplies at plants around New England declined rapidly over the two-week cold spell as gas prices spiked and dual-fuel plants switched to oil, but the RTO avoided serious reliability issues thanks to LNG shipments. (See *FERC, RTOs: Grid Performed Better in Jan. Cold Snap vs. 2014*.)

Testifying before the U.S. Senate Energy and Natural Resources Committee on Jan. 23, van Welie said that since 2000, oil- and coal-fired generation's share of ISO-NE's power production has fallen from 40% to less than 10%, while natural gas has risen from 15% to about 50%.

The outlook noted that wind power last year for the first time surpassed natural gas for the volume of generation seeking interconnection in the RTO's queue. About 4,000 MW of that proposed wind would be located offshore of Massachusetts, with most of the remaining 4,500 MW slated for Maine.

"Because of the large distances from some of the proposed onshore wind power projects to the existing grid, major transmission system upgrades will be needed to deliver more of this power from this weaker part of the system to far-away consumers," the report says.

As the amount of wind and solar power continues to grow, in part driven by state policies, the RTO last month proposed a new two-stage capacity auction, Competitive Auctions with Sponsored Policy Resources, to enable its Forward Capacity Market to accommodate state policy-sponsored, clean-energy resources in the wholesale market while maintaining a viable economic model for existing power plants. (See *CASPR Filing Draws Stakeholder Support, Protests*.)

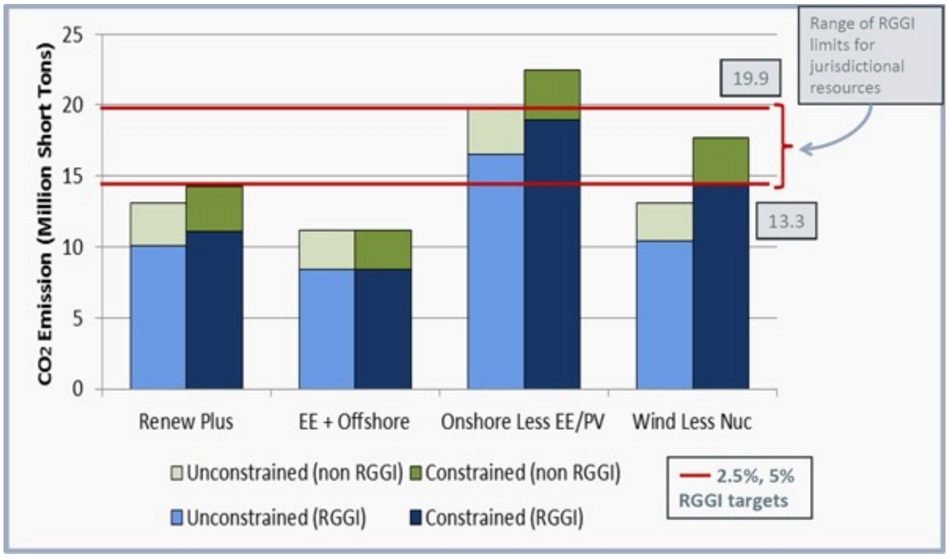
The RTO also says it's keeping an eye on the increased adoption of electric vehicles and electric heating in New England as states in the region pursue decarbonization goals.

"The ISO plans to start working with regional stakeholders to quantify the impact of the states' decarbonization policies on long-term demand so that we can understand their potential effects on the power system and reflect these in future Regional System Plans," the report says.

ISO-NE NEWS

ISO-NE Study Finds Wind 'Spillage,' Price Separation

By Rich Heidorn Jr.



Only one scenario, EE + Offshore, is as good as the Renewables Plus scenario in meeting the RGGI 2030 emission targets. | *ISO-NE*

ISO-NE could see substantial "spillage" of renewable energy and large price separations because of transmission constraints under scenarios considered in the RTO's 2017 Economic Study, officials told the Planning Advisory Committee on Wednesday.

The study was requested by the Conservation Law Foundation to evaluate scenarios for meeting Massachusetts and Connecticut climate laws and the Regional Greenhouse Gas Initiative's emission caps.

The study was based on the "Renewables Plus" scenario from the 2016 Economic Study, which modeled the year 2030 — the only scenario in the 2016 study to meet the RGGI cap. (See *Study: New Resources Could 'Crowd Out' Old in ISO-NE*.)

Under Renewables Plus, the generation fleet met existing renewable portfolio standards, and new renewable or clean energy resources were added above existing RPS requirements.

The new study looked at three additional scenarios:

- "EE + Offshore": Added more energy efficiency and offshore wind while reducing imports from Canada by 1,000 MW.
- "Onshore Less EE/PV": A variation on the business-as-usual base case from the 2016 report, with onshore wind boosted to 7,000 MW (nameplate capacity) from 4,800 MW in the reference case.
- "Wind Less Nuc": Assumes the Millstone nuclear plant retires by 2030, five years ahead of its license expiration, with the gap filled by renewable/clean energy resources.

The study found all three scenarios met projected demand, even with transmission constraints based on the "as-planned" system's internal and external transfer limits.

If transmission constraints are not relieved, the RTO would see "spillage" of wind power north of the Surowiec-South interface, leading to lower prices in Northern Maine than southern New England. For example, under the constrained scenarios, 7 to 18% of renewables would be spilled, with 22 to 89% of the spillage north of Surowiec-South.

In the constrained Wind Less Nuc scenario, average LMPs would range from $13.78/MWh in the Bangor Hydro Electric subarea in northeastern Maine, to $38.71/MWh in the NH subarea (which includes most of New Hampshire, eastern Vermont and southwestern Maine) and $37.18/MWh in Boston.

Electric production by natural gas plants fluctuates with assumptions regarding plant retirements and price-taking offers ($0/MWh) by renewable resources. EE + Offshore has the least gas-fired energy, while Wind Less Nuc has the most gas production, especially when the transmission system is constrained.

EE + Offshore had the lowest total production costs, coming in 28% below the Renewables Plus reference case assuming transmission constraints. Onshore Less EE/PV had the highest costs, 77% above the constrained reference case.

Only one scenario, EE + Offshore, is as good as the Renewables Plus scenario in meeting the RGGI 2030 emission targets.

CLF staff attorney David Ismay said the two emission-reduction targets, which were also used in the 2016 study, were intended to "bracket" the goals RGGI might embrace in its latest program review.

RGGI's emissions cap declines by 2.5% annually through 2020. The group announced in August that it would seek an additional 30% reduction in emissions from 2020 levels.

"We expressly worked … to design all three scenarios to meet [RGGI] emissions targets," Ismay said.

"We're starting to get a better picture of what the grid needs to look like in order to meet our climate laws and emission regulations that are already on the books," he explained in an interview later.

"We really need a grid that's different from what we have now. I think that will give legislators, regulators and the ISO information on the kind of mix we need to comply with these laws. … It's really helpful to see the impact of adding 1,000 MW of EE or 1,000 MW of wind."

Stakeholders have until April 2 to submit requests for additional economic studies. Requests should be emailed to PACMatters@ISO-NE.com.

ISO-NE NEWS

ISO-NE, Mass. Set Ride-Through Rules for Solar PV

By Rich Heidorn Jr.

ISO-NE is asking distribution utilities in the region to adopt interim ride-through requirements for solar PV inverters that it developed with Massachusetts stakeholders, the RTO told its Planning Advisory Committee on Wednesday.

The RTO said it needs to ensure solar PV generation can remain stable during voltage and frequency excursions because of its rapid growth in the region. The RTO's 2014 forecast predicted about 1,750 MW of solar by 2022. By 2016, however, the RTO had almost 2,000 MW, and the 2017 forecast predicts 4,000 MW by 2022. Massachusetts, home to 60% of the RTO's solar resources, is expected to double its PV capacity in the next decade.

The new rules are laid out in a source requirement document (SRD) ISO-NE developed with the Massachusetts Technical Standards Review Group, which includes representatives from developers, manufacturers, state regulators and utilities Eversource Energy and National Grid.

The SRD requires that solar inverters have voltage and frequency trip settings and ride-through capabilities and be certified under UL 1741 SA, the safety standard for inverters and interconnection system equipment used in distributed energy resources.

ISO-NE's David Forrest said the SRD represents an effort to balance transmission and distribution system needs. "Ideally, we'd like DER to ride through any of these faults on the transmission system, [but] … we also have to look at issues on the distribution system," he said. "So what the ISO is proposing is kind of a compromise between meeting the transmission needs and meeting the distribution needs."

In Massachusetts, inverter-based solar PV projects greater than 100 kW will be subject to the new rules for interconnection applications submitted on or after March 1. Projects of 100 kW or less will be subject to the rule on June 1.

The RTO hopes utilities in all states will adopt the SRD, saying having one set of requirements for the region will minimize developers' costs and simplify the modeling of DER in planning studies.

National Grid will require it in Rhode Island, and United Illuminating and National Grid are "looking at implementing the requirements" in Connecticut, Forrest said.

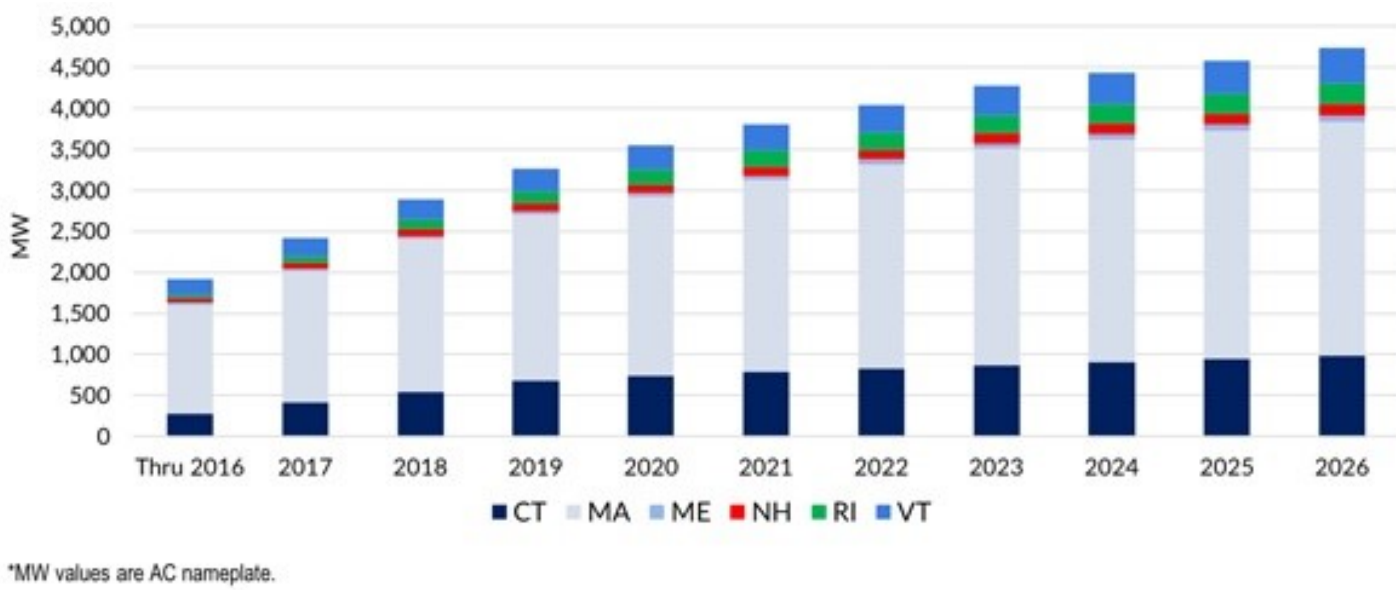
The Energy Policy Act of 2005 requires electric utilities to provide interconnection services based on the Institute of Electrical and Electronics Engineers' (IEEE) Standard 1547 (Interconnecting Distributed Resources with Electric Power Systems).

ISO-NE said the SRD is "consistent with" Standard 1547 and can be met by all inverters certified under UL 1741 SA. "The key here is that we know that inverters meeting UL 1747 SA are available," said Forrest.

The RTO sought interim rules while IEEE completes its work on a revised Standard 1547, he said. The institute hopes to complete Standard 1547.1 by late this year or early 2019. Once the revised standard is approved, UL 1741 SA will need to be updated to agree with the revisions, and it will take a year or longer for all inverter manufacturers to have their inverters tested and certified by safety company UL.

As a result, the RTO said it will be 2020 or later before utilities will be able to require use of the revised standard.

The SRD does not cover inverters for fuel cells, traditional generators or energy storage, although they may be covered in the future, Forrest said. "Down the road we may have to look at electric vehicles," he added. "This isn't a topic that is going to go away."



ISO-NE final 2017 PV forecast | *ISO-NE*

ISO-NE NEWS

Mass. Picks Avangrid Project as Northern Pass Backup

Continued from page 1

of Canadian hydropower to the New England grid via a 145-mile transmission line. The partners estimate the project to cost $950 million.

News of the selection drew a protesting tweet from Dan Dolan, president of the New England Power Generators Association: "Massachusetts is now all-in on Hydro-Quebec, going from the fatally flawed Northern Pass to a Maine project that still lacks virtually all its key permits. Hydro-Quebec is asking for Massachusetts consumers to guarantee them revenue through an above-market contract for electricity for the next two decades."

Dolan said existing power plant operators in the region have invested more than $13 billion in their plants without any guarantee of cost recovery or profit.

Beginning Negotiations

CMP submitted applications for state and federal permits for NECEC in mid-2017 and said it expects to receive state approvals later this year and final federal permits in early 2019. The company said it will immediately begin negotiation of long-term contracts with the Massachusetts electric distribution companies to prepare for a submission to the state's Department of Public Utilities in April 2018.

"Our applications for state and federal permits are moving forward with the strong support of communities and stakeholders in Maine," CMP CEO Doug Herling said in a statement.

Eversource's statement said that Friday's decision "strikes a sensible balance by allowing negotiations with Northern Pass to continue, while establishing a back-up protocol that can be initiated if necessary."

Avangrid Networks CEO Bob Kump said, "A new transmission link between Maine and Quebec would deliver a reliable, firm supply of clean energy to help dampen seasonal price instability when high demand puts pressure on natural gas supplies."

Massachusetts issued its MA 83D solicitation for hydro and Class I renewables (wind, solar or energy storage) last July. The selection committee for the clean energy request for proposals issued in July 2017 includes representatives from the state's Department of Energy Resources and from distribution utilities Eversource, National Grid and Avangrid subsidiary Unitil.

Any contract awarded under the request for proposals must be negotiated by March 27 and submitted to the DPU by April 25.

Other proposals for the RFP included Nova Scotia-based Emera's Atlantic Link project, a 375-mile submarine HVDC transmission line from New Brunswick to Plymouth, Mass., to deliver 5.69 TWh of clean energy per year. National Grid partnered with Citizens Energy on two transmission projects; one of them, the Granite State Power Link, is a 59-mile HVDC line from northern Vermont to New Hampshire to deliver 1,200 MW of new wind power from Canada.

The state-owned Hydro-Quebec also partnered separately with Transmission Developers Inc. for the RFP and, as with Northern Pass, made two proposals, one pure hydro and one with a wind energy component.

FERC OKs MISO Queue Changes, Orders Fewer Restudies

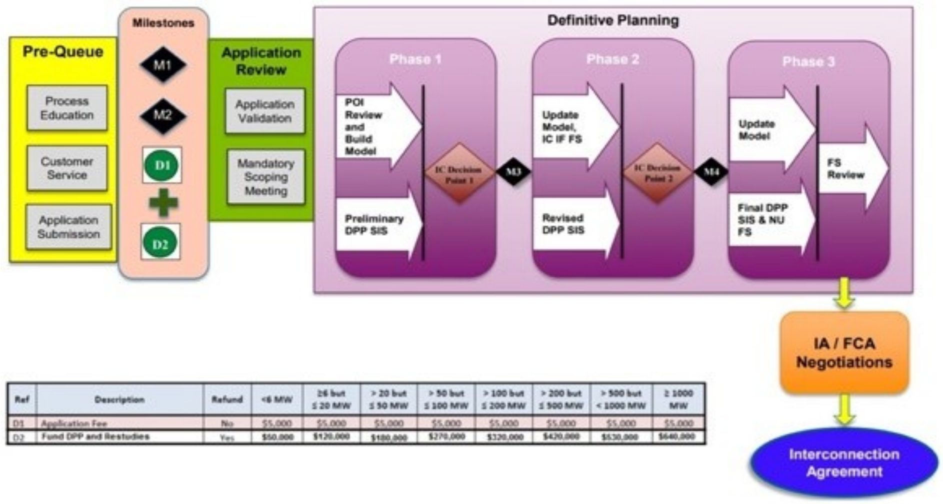
By Amanda Durish Cook

FERC last week accepted several small revisions to MISO's new interconnection queue design but also told the RTO it must keep working to ensure it sticks to a commitment to reduce restudies.

The commission provided MISO a month to revise its Tariff to eliminate a practice of automatically conducting a restudy based on predetermined triggers, which include a project's termination or the withdrawal of a project from the queue (ER17-156-002).

"In the October 2016 queue reform filing, MISO proposed that, instead of conducting a restudy automatically upon each occurrence of a restudy trigger, MISO would re-evaluate the need for any common use or shared network upgrades associated with the project," FERC said.

FERC largely accepted MISO's new, three-stage interconnection queue in January 2017, but it sought more detail on a few aspects of the plan, prompting a follow-up filing. (See *FERC Accepts MISO's 2nd Try on Queue Reform*.) The commission at the time directed MISO to conduct restudies on an as-needed basis only, even when a triggering event occurs. It said the RTO "could decide in its discretion whether a restudy was needed or not."



MISO's new generation interconnection process | *MISO*

In revisions filed last March, MISO altered its Tariff to enable it to conduct restudies for reasons other than triggering events. In the most recent ruling, FERC reversed that move, saying MISO cannot conduct a restudy absent a trigger.

FERC accepted several other smaller Tariff revisions that it had directed MISO to make, including:

- Stipulating mandatory attendance of transmission owners in scoping-level meetings between MISO staff and interconnection customers;
- Describing the types of events that trigger a queue restudy; and
- Offering customers a provisional generator interconnection agreement option at any time in the interconnection process, regardless of whether MISO failed to meet a study deadline.

MISO was also required to scale back its site control requirement by the queue's second decision point from 100% to 75% after FERC determined that complete site control is difficult to obtain so early in the process.

The RTO also had to clarify that an interconnection customer that withdraws early in the queue — at either the first or second decision points — will not be responsible for the costs of other customers' interconnection studies, and that a customer withdrawing at the third decision point should only pay a study deposit fee to cover a potential restudy for another interconnection customer.

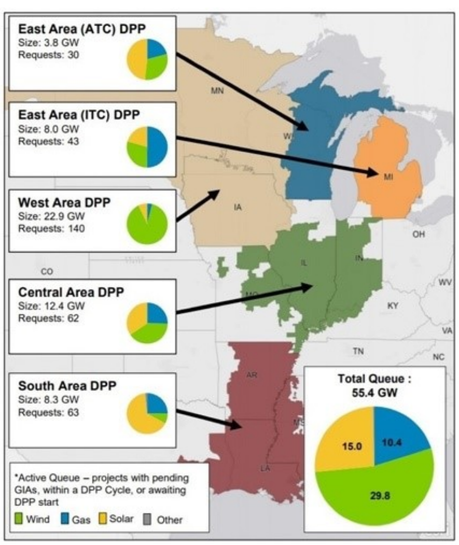
Finally, MISO added language to clarify that the batch of projects entering the definitive planning phase in August 2015 was grandfathered into the old queue design.

However, FERC's recent ruling gave MISO 30 days to clarify that the queue's third and fourth $4,000/MW milestone payment collection is only an initial charge subject to change as costs become clearer in the study process.

"This language implies that the M3 and M4 milestone payments are set to $4,000/MW and are not subject to a true-up as more accurate estimates become available, which is not in line with MISO's indication in its testimony," FERC said.

In accepting MISO's filing, FERC dismissed a bundle of complaints from EDF Renewable Energy as being outside the scope of the proceeding. EDF had asked FERC to force MISO to share more network modeling details and prescribe "remedies" should the RTO fail to complete studies on time. The company also sought a directive instructing MISO to develop a fast-track queue option for vetted projects, and complained that the RTO failed to coordinate its generator interconnection process with the transmission planning process.

Another EDF complaint against MISO's new queue design is still outstanding. (See *Renewables Developer Escalates MISO Queue Design Dispute*.)



MISO active queue by study area, as of November 2017 | *MISO*

MISO NEWS

MISO Plans Interregional Improvements with SPP

By Amanda Durish Cook

CARMEL, Ind. — MISO is weighing how it can improve its interregional process and joint operating agreement with SPP to make it easier to develop cross-seams projects that have so far remained elusive.

The RTOs have conducted two coordinated system plan studies that have failed to produce an approved interregional project, although they have studied several candidate projects. (See *MISO Confident in Tx Process with SPP Despite Lack of Projects*.)

“The assumption is the coordinated system plan is not setting us up for success,” Eric Thoms, MISO manager of interregional planning and coordination, told stakeholders at a Feb. 14 Planning Advisory Committee meeting.

Planning staff for both RTOs have agreed to meet this spring to devise ways to improve their joint study process.

Thoms said MISO is considering lowering hurdles for interregional projects, including removing the $5 million cost threshold and eliminating the joint model study requirement, which he said is unnecessary when the RTOs’ separate regional evaluations can adequately examine prospective interregional projects.

Eric Thoms | © *RTO Insider*

He also said the RTOs might identify more joint benefit metrics that could better illustrate the value of potential transmission projects and clarify to stakeholders the process for approving interregional projects.

However, some stakeholders said the RTOs must first address their disparate transmission usage charges before working toward interregional project approval.

“I’m glad to see MISO is trying for constituency between seams, but MISO and SPP have incompatible [unreserved usage charges],” said Minnesota Public Utilities Commission staff member Hwikwon Ham. Until the RTOs have comparable transmission usage charges, interregional projects will be difficult to approve, Ham said.

Xcel Energy’s Drew Siebenaler agreed the RTOs must discuss transmission service charges and resolve the issue of MISO consistently bearing more costs for potential projects that stand to benefit both sides of the seam.

Adam McKinnie, chief economist with the Missouri Public Service Commission, asked that the charges not be the lone hang-up in approving a possible near-term interregional project. Thoms promised to return to the PAC in April to further discuss the topic.

The next Interregional Planning Stakeholder Advisory Committee meeting will be held Feb. 27. Officials from both RTOs plan to present a more detailed coordination plan during the meeting.

MISO: Minimal Change to 2019 Tx Planning Futures

By Amanda Durish Cook

CARMEL, Ind. — MISO expects the 15-year future scenarios informing its 2019 Transmission Expansion Plan to look much like those for 2018.

“There haven’t been any significant economic and policy changes. We can tweak and refresh these [2018] futures and adapt them for MTEP 19,” MISO Planning Manager Tony Hunziker told stakeholders at a Feb. 14 Planning Advisory Committee meeting.

Hunziker said MISO planners found the Trump administration’s plan to pull the U.S. out of the Paris Agreement on climate change will do little to disrupt the trajectory of the RTO’s renewable penetration trends.

MISO last year assembled MTEP 18 futures designed to be reused over multiple years, provided there aren’t extreme policy changes or economic shifts. The four futures include a limited fleet change future; a continued fleet change future; an accelerated fleet change future; and a future in which distributed and emerging technologies become more widely used in the footprint. (See *MISO Ranks MTEP 18 Futures by Stakeholder Preference*.)

As it promised, the RTO will apply an even 25% likelihood weighting to each of the four futures, effectively eliminating the weights. MISO had originally sought to apply equal weights in MTEP 18 but had to delay the plan for a year after stakeholders — especially from MISO South — insisted on having a say in deciding the futures’ likelihood. (See *MISO Delays Removing MTEP Futures Weighting to 2019*.)

This year, MISO projects a slight dip in load-serving entities’ demand forecasts, with the latest overall RTO forecast trending lower than forecasts prepared to inform MTEP 18. MISO now expects demand to grow at a preliminary 0.3% rate, lower than MTEP 18’s 0.5% growth rate and keeping the forecasted non-coincident peak below 136 GW through 2026. Hunziker said MISO has not yet rerun a resource forecast with the updated data.

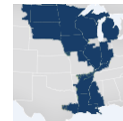
The RTO now anticipates lower natural gas costs, predicting prices will remain below $6/MMBtu through 2033, compared with last year’s prediction of $6.50/MMBtu.

MISO also found that, compared to its MTEP 18 estimates, the capital cost of building new generation will slightly decline for all fuel types, except for coal, which increases slightly, and utility-scale solar, which decreases more dramatically from about $2,000/kW to $1,200/kW.

Forecasted coal retirements are predicted to hold steady, with MISO estimating that about 35 GW will shut down by 2032.

MISO will hold a March 20 workshop to further refine MTEP 19 futures with stakeholders. Hunziker asked for stakeholders to submit their comments about the reuse of futures and the RTO’s predictions by March 2.

MISO NEWS



Trade Group Seeks Expanded DR Measures in MISO

By Amanda Durish Cook

A distributed energy resource trade group is calling on MISO to open its markets to customer-owned demand response and urging state regulators and utilities to develop programs that reimburse small DR providers.

The Advanced Energy Management Alliance (AEMA) last week issued a white paper containing model Tariff language intended to extend access to MISO's wholesale markets to customer-owned demand-side resources.

The white paper suggests that states in the RTO's footprint adopt DR programs like those in New York and the portion of Indiana in PJM.

"While not new to the Midwest, the growth and development of demand response in the region has largely stagnated," AEMA wrote. "To create shared value for utilities and consumers, states should take near-term action to create robust demand response programs where demand response is lacking and evolve demand response program design in territories that have had the same tariffs for over a decade."

Like in the PJM area of Indiana, AEMA suggests having utility-qualified DR providers register their customers with a utility, which would then enroll the customers in MISO's DR program. The utility would receive capacity credit for customers they enroll, and DR providers would get either an average price from MISO's annual capacity auction or 35% of the net cost of new entry. AEMA said the approach would be "an effective means for stimulating cost-effective DR while working within existing state and MISO market constructs."

As an alternative, AEMA said MISO could adopt New York-style programs that concentrate on reducing transmission and distribution costs and stay independent of wholesale capacity programs.

The organization also said that if states agree, MISO could devise Tariff rules for peak load management, distribution-level services and, eventually, additional wholesale market programs.

AEMA also suggested that Midwestern states allow bilateral contracting between utilities and DR providers. Under this scenario, the utility and the provider contract for a specific number of megawatts for enrollment, a price per megawatt and program design — including the terms of dispatch.

"AEMA is eager to collaborate with MISO-based utilities, regulators and system operators in this endeavor. Our goal is not to overturn existing bans that prohibit demand response providers from directly enrolling customers in wholesale market programs, but instead to develop new creative approaches to exploiting the full potential of demand response," the group said.

It said new DR resources are less expensive than running aging generation.

"Energy leaders in the Midwest should not let excess capacity stop them from pursuing all cost-effective demand response," the organization said.

AEMA Executive Director Katherine Hamilton said the white paper is a "roadmap" for state regulators and utilities.

Hamilton

"We hope that this white paper is used as intended — to inform and offer options for regulators and utilities seeking to partner with third-party providers and consumers. AEMA members seek to grow our businesses while giving consumers additional choices and providing cost-effective, environmentally sustainable services to the electric grid," Hamilton said.

Several utilities in MISO states have interruptible DR programs, but AEMA said those programs need to evolve.

MISO had 10.7 GW of wholesale DR capacity in 2016, 8.9% of its annual load peak. The RTO's DR is mostly derived from interruptible load and behind-the-meter generation under state-regulated and utility-run programs and accredited as load-modifying resources or emergency demand resources.

MISO Fast-Tracks ATC Foxconn Project Review

CARMEL, Ind. — MISO will expedite review of a proposal to interconnect Foxconn's massive electronics plant planned for southeastern Wisconsin months ahead of the RTO's usual year-end approval schedule, stakeholders learned Wednesday.

The $140 million interconnection project to plug Foxconn's $10 billion plant into We Energies' network will move ahead "as needed to meet the December 2019 in-service date," Lynn Hecker, MISO manager of expansion planning, said at a Feb. 14 Planning Advisory Committee meeting.

American Transmission Co. submitted the request for accelerated approval late last year, insisting that its proposed project cannot wait until usual approvals at the end of the year as part of MISO's 2018 Transmission Expansion Plan. ATC has proposed constructing a 14-mile, 345-kV transmission line; a new 345/138-kV substation; and new underground 138-kV lines to connect the substation to a smaller Foxconn-owned substation near the plant. (See *MISO Seeks Stakeholder Input on Foxconn Decision*.) MISO's decision was based on ATC's forecasted load of 230 MW, although Foxconn says there's potential for campus expansion at the site, possibly adding another 200 MW of load.

Stakeholders had little to say about the project, although some asked the RTO to make more widely circulated announcements when it wraps up expedited review studies and when it plans to announce expedited decisions.

— Amanda Durish Cook

MISO NEWS

OMS Board of Directors Briefs

Clean Energy Advocate Urges New Tx Tech

A clean energy consultant told Midwest regulators last week that a future footprint with more renewables would benefit from modern transmission technologies.

Rob Gramlich, president and founder of Grid Strategies, said transmission technologies — dynamic line ratings, flow control devices and network topology optimization — will help manage congestion.

"We're looking at a future where there are a lot of low-cost but remote resources," Gramlich told the Organization of MISO States' Board of Directors at the National Association of Regulatory Utility Commissioners' annual meeting.

Gramlich said the technologies have improved dramatically and are ready for use today, but they need to be better valued monetarily.

"They're there and ready, but the incentives aren't in place," Gramlich said. "It's just hard to get low-cost improvements because they can't be rolled into transmission owners' rate base. … There's a gap that state regulators can address."

Dynamic line ratings are adjusted based on weather conditions, opening up transmission lines for more capacity when temperatures are cooler. Network topology optimization uses software to improve scheduling of transmission outages. Gramlich also said power flow control devices, like phase angle regulators, played a key role in PJM managing loads during the early January bomb cyclone cold snap.

"Operate the existing grid more efficiently and get more out of it," Gramlich urged.

He expressed surprise at how many line limit and flow thresholds on the bulk power system are not exactly known, only estimated. "It's not so often measured," Gramlich said.

It's time for the industry to develop a technology-managed smart grid, he continued, noting that much of the country's sewer flows are managed through technology.

Such technologies are more widely used abroad, where incentives are in place, Gramlich said, pointing to Belgium, which makes widespread use of dynamic line ratings.

OMS DER Survey Begins

The board kicked off an effort to collect data from load-serving entities on the volume of distributed energy resources participating in their service territories.

OMS will survey LSEs across MISO through March 30 on the current and projected state of DER in their territories. The group plans to analyze the data to get a better understanding of the "structure, scope and pace of DER development in MISO."

The survey is part OMS' ongoing initiative to help state and local regulators make informed decisions as increased DER adoption potentially dictates the need to develop policy around the interaction between distribution and transmission systems. Last year, OMS formed a temporary working group to formulate ideas on incorporating DER into the grid after holding a MISO-wide workshop. (See *OMS Discusses Next Steps in DER Policy*.)

"The OMS board has made DER a priority because of the inherent jurisdictional overlap raised by future integration of DER connected to the distribution system into transmission-level planning, operations, and energy markets," OMS President, and chair of the Arkansas Public Service Commission, Ted Thomas said in a statement.

"In a multistate region, it's critical that cooperation among states and their utilities occurs to provide the necessary visibility to DER deployment that enables the continued efficient and reliable operation of the bulk electric system," said OMS Vice President Daniel Hall, chair of the Missouri Public Service Commission.

— Amanda Durish Cook

MISO NEWS

MISO Recommends Cost-Sharing for Sub-345-kV Tx

By Amanda Durish Cook

CARMEL, Ind. — MISO is proposing to eliminate a footprint-wide postage stamp rate and change its rules for market efficiency projects to include regional cost allocation for transmission projects under 345 kV.

The RTO wants to lower its cost allocation threshold to cover 230-kV projects, a move that Director of Strategy Jesse Moser said will capture a reality in the footprint, where 230-kV lines are prevalent and transport a high volume of electricity.

Speaking at a Feb. 13 Organization of MISO States (OMS) board meeting, Moser pointed out that certain parts of the RTO operate at a maximum 230-kV rating, especially in MISO South. That voltage represents a "sweet spot for effective mitigation of congestion," according to MISO.

"This puts essentially the whole footprint on an equal playing field in terms of getting a cost-shared project approved," Moser said.

Postage Stamp Removal

MISO is also recommending that it scrap its footprint-wide postage stamp rate for market efficiency projects. The RTO currently allocates 80% of project costs to local resource zones based on expected benefits and recovers the other 20% via postage stamp allocation to all regional load. Instead, MISO wants to assign all costs to benefiting transmission pricing zones and work with stakeholders to create more specific benefit metrics. The move will make for "more granular, more targeted cost allocation," Moser said.

MISO currently relies on the postage stamp rate as a means of recognizing both transmission benefits not currently quantified within its cost allocation and the changing nature of beneficiaries as the fleet evolves.

Currently, there is no regional cost allocation within MISO for transmission projects below 345 kV, and Minnesota Public Utilities Commission staff member Hwikwon Ham said if it were to abolish its postage stamp rate, it should detail a much more precise set of valued benefits.

In adding new benefit metrics for cost allocation, Moser said MISO may consider aspects such as deferred reliability projects and savings that could arise from opening up the contract flow path with SPP that bridges MISO South and Midwest.

"The benefit metrics discussion will continue," Moser promised state regulators.

Wind on the Wires' Natalie McIntire asked MISO to devise a benefit metric for projects that facilitate state renewable portfolio

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MISO Evaluating Economic Modeling for Tx Projects

By Amanda Durish Cook

MISO is embarking on a review of its entire economic planning process in an effort to more accurately capture the benefits of cost-shared transmission projects.

"This is not about MISO saying the existing process is broken or flawed," Matt Ellis, of the RTO's Economic Planning Users Group, told stakeholders at a Feb. 13 Planning Subcommittee meeting.

Ellis said MISO is looking forward to FERC-level discussion on best practices for planning and that it will continue to talk about economic models throughout 2018.

MISO especially wants to take a fresh look at:

- The economic impacts of transmission outages;
- Voltage and local reliability resource commitments, especially in MISO South load pockets where performance has lagged;
- MISO's emergency energy supply and how it's being valued in economic models when it defers transmission and generation investment or prevents scarcity pricing and loss-of-load events;
- Accounting for likely import and export flows in adjusted production costs; and
- Forecasted renewable resource ownership and which members will actually purchase the energy and benefit when considering renewable portfolio standards.

Further, the RTO plans to hold stakeholder discussions through June on other possible measurable benefits that could be valued in the modeling of market efficiency projects. It could consider such benefits as the deferral of reliability projects; savings that could arise from opening up it contract flow path with SPP that bridges MISO South and Midwest; reduced transmission energy losses; reduced ancillary services costs; and deferral of capacity expansion stemming from increased capacity import/export limits.

Ellis asked for member companies' engineers to come forward with other ideas about overlooked benefits of market efficiency projects that could be assigned a monetary value.

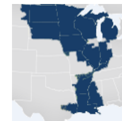
Minnesota Public Utilities Commission staff member Hwikwon Ham cautioned that renewable standards are set by state legislatures and can be changed. Ellis responded that MISO is looking for that kind of information and other input.

He also said timely changes to MISO's modeling could affect how it judges potential projects in its annual Market Congestion Planning Study for the 2018 Transmission Expansion Plan.

"We are fully aware that having a process review in parallel with having the process is not an ideal situation. It introduces a lot of 'what-ifs,'" Ellis said. He promised that MISO would test any projects affected by an economic model change using both the old and new models and that it could delay implementing the new aspects of economic modeling.

MISO announced its plan the same week it proposed to lower the voltage threshold for market efficiency projects to 230 kV, and two weeks after FERC ordered a technical conference on how PJM, MISO and SPP coordinate generator interconnection studies after developer EDF Renewable Energy complained that the RTOs' modeling standards violate the FERC requirement for transparent open access interconnection service. (See *FERC Orders Review of PJM, MISO, SPP Generator Studies*.)

MISO NEWS



MISO Recommends Cost-Sharing for Sub-345-kV Tx

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standards.

The RTO will also consider creating smaller transmission cost allocation zones for a more targeted cost allocation and will hold discussions with stakeholders, Moser said.

However, MISO will leave some market efficiency project requirements untouched, including the benefit-based allocation to all zones, a required benefit-to-cost ratio of at least 1.25:1 and the $5 million minimum project cost threshold.

The proposed changes would not apply to multi-value projects. Moser said stakeholders offered "a lukewarm response" to any possible changes to those projects.

MISO is seeking to draft a nearly final allocation proposal by June, with a FERC filing to follow in September or October. It hopes to get approval by the end of the year and introduce the new allocation in early 2019.

Entergy's integration transition period, which limits cost sharing in MISO South, expires at the end of this year. The RTO has not revised its cost allocation rules since the integration of South in 2013.

'Something You All Can Live With'

"We're certainly zeroing in on some specific reforms," Moser told stakeholders at a Feb. 15 Regional Expansion Criteria and Benefits Working Group (RECBWG) meeting. "We really tried to find areas where we could get broad support. We hope the overall package is something you all can live with."

Xcel Energy's Carolyn Wetterlin, chair of the RECBWG, reminded stakeholders that no allocation proposal will satisfy every stakeholder's wish list.

"We're getting into that phase where we really have to think about what we're solid on and where we could give a little as we move toward a filing," Wetterlin said.

Some stakeholders at the meeting asked for MISO to consider lowering the threshold further to 100 kV, given that some 100-kV projects are needed for reliability and provide economic benefits. Others pointed out that two years ago, FERC ordered a 100-kV minimum threshold for interregional market efficiency projects with PJM. But MISO has yet to propose a regional cost allocation for interregional economic projects down to 100 kV on the PJM seam.

MISO itself originally considered a 100-kV cost allocation threshold for market efficiency projects in a draft proposal issued last year.

Moser said 100-kV lines with solid business cases will still be eligible for local cost allocation, but the RTO prefers that costs for such low-voltage projects are not shared footprint-wide.

"We looked at all the perspectives we heard over the last year, and we view the 230-kV threshold as a reasonable compromise," Moser added.

Since Entergy's integration into MISO, the RTO has approved two 230-kV projects in MISO South that qualified under the "economic other" category, which are only eligible for recovery in zonal rates.

Other stakeholders argued for MISO keeping the 345-kV status quo, with one stakeholder saying lower voltage "Band-Aid projects" with limited footprint-wide benefits should not be allocated like higher-voltage "backbone" projects.

Last September, MISO Vice President of System Planning Jennifer Curran told the Board of Directors that the RTO anticipated a range of opinions among stakeholders on cost allocation approaches.

"It's not surprising that we've heard a very large number of opinions," Curran said at the time. "The one thing that holds true is that when MISO recommends transmission, we have to have a good, strong business case. We can't recommend things that we don't think will get passed."

MISO will continue the cost allocation discussion with stakeholders at the March 15 RECBWG meeting.

NYISO NEWS

NY Task Force Debates Carbon Pricing Models

By Michael Kuser

New York's Integrating Public Policy Task Force (IPPTF) last week debated a proposal seeking to align the state's effort to price carbon with the Regional Greenhouse Gas Initiative. It also discussed an alternative to NYISO's capacity market.

Representatives from the Long Island Power Authority (LIPA) and National Grid made presentations as part of the ongoing process to develop a straw proposal for pricing carbon into the state's wholesale electricity market, a joint effort by NYISO and the state's Department of Public Service (17-01821) that aims to deliver a workable plan by year's end.

The IPPTF's work plan includes five issue tracks: 1) straw proposal development; 2) wholesale energy market mechanics and interaction with other wholesale market processes; 3) policy mechanics, such as setting the carbon charge; 4) interaction with other state policies; and 5) customer impacts. (See *NYC, Goals Dominate Talk on Carbon Pricing*.) The effort is still in the first track, slated to conclude March 19.

Regional Circuit Breaker

During his presentation, LIPA Director of Power Markets Policy David Clarke asked that "NYISO and DPS think about the carbon abatement cost curve throughout the RGGI region, what it might look like, what it might cost to buy and retire allowances along the curve and how far we might go to narrow differences by doing so, especially considering the roles of the cost-containment reserve." The RGGI reserve contains allowances only released if allowance prices exceed predefined levels.

New York could reduce its carbon emissions at a lower cost by drawing on the broader region and a wider geographic set of abatement alternatives, Clarke said.

"RGGI has a 10-million-ton reserve, priced in 2025 a little over $17 a ton. Essentially, it's a circuit breaker," Clarke said. "So RGGI states have agreed to this circuit breaker, a price increase they can live with if the market's carbon price went too high."

LIPA considers the state's Clean Energy Standard (CES) goals — principally, an 80% emissions reduction by 2050 — as a starting point for pricing carbon and wants NYISO to consider an approach that increases the state's carbon prices to the RGGI cost-containment reserve price. The power agency noted that the draft 2017 Policy Scenario Overview, prepared by ICF International for RGGI in June 2017, pointed to a "wide range" of projected 2025 allowance prices, "the lowest of which accompany high renewable build-out scenarios, but most are well below $17/ton for 2025."

Clarke noted that, in The Brattle Group's report on the social cost of pricing carbon in New York, the "starting point was a $40 adder above the assumed $17 price, so they were looking at $57-58/ton as the carbon adder."

"The Brattle proposal is to take the carbon price and raise it into the marketplace and get some marketplace reductions, and it raises it quite a lot," said Mark Reeder of the Alliance for Clean Energy New York. "And [LIPA] seems to be proposing as an alternative to that — [that] New York retires RGGI allowances and raises the price in the market for carbon that New York sees. But it's not just New York; it's everybody else [that sees a higher price], and it's an alternative way of getting the market to see a higher price of carbon."

Clarke agreed that was "a more or less" accurate summary of LIPA's thinking.

"We observe that the RGGI prices are likely to trade well below the cost-containment reserve level if nothing changes," Clarke said. "And from a loads perspective, buying and retiring allowances below this price can be significantly less expensive than the average cost loads would pay under an approach that sets a carbon adder at the social cost of carbon."

Under current regulations, any entity, including a state or load-serving entity, can set up an account to buy allowances. RGGI regulations also provide for retiring allowances from voluntary reductions, so there are a couple mechanisms to buy or retire allowances up to the cost-containment reserve price, Clarke said.

Alternative Market Design

Ben Carron, National Grid's senior analyst for regulatory strategy and integrated analytics, presented the company's Dynamic Forward Clean Energy Market (DFCEM) concept, an alternative to the capacity and renewable energy credits markets in New York. Under the idea, the state would use an auction to procure the clean energy attribute from a resource, but not the energy itself. The model is designed to incentivize development of new clean energy resources and retain existing ones in order to reduce emissions.

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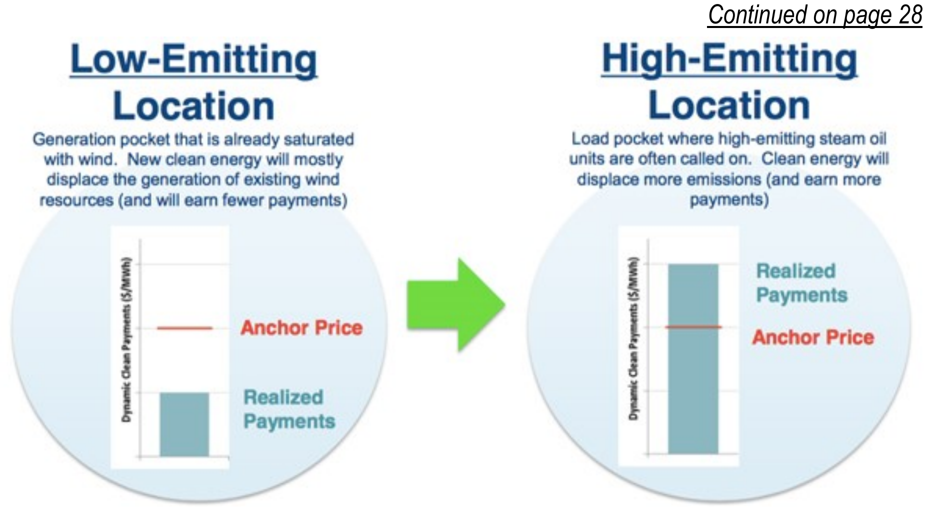

Locational incentives for clean energy | *The Brattle Group*

NYISO NEWS

FERC: NYISO Still Lagging on Order 1000 Rules

By Michael Kuser

FERC ruled Thursday that NYISO must make additional changes to comply with Order 1000, while acknowledging in a separate docket that it erred in directing the ISO to change the indemnification language in its *pro forma* development agreement.

The commission said transmission developers must indemnify NYISO except for acts of "gross negligence or intentional misconduct." In ordering NYISO to remove the word "gross" from the agreement, the commission said it failed to follow its precedent in a 2015 order involving MISO (ER15-2059-002; ER13-102-008).

FERC also granted NYISO a request for clarification, saying it will allow the ISO to propose a new process for evaluating alternative regulated transmission solutions and regulated backstop solutions for interconnection. The ISO's current process is outlined in Tariff Attachments X and S.

But the commission rejected rehearing requests by the New York Transmission Owners (NYTOs), who balked at the commission's requirement that TOs responsible for providing "backstop" solutions to a reliability need — normally the incumbent TO — sign the development agreement, as is required of nonincumbent transmission developers.

"If responsible transmission owners developing regulated backstop solutions are not required to execute a development agreement, they will have an advantage over nonincumbent transmission developers both in seeking selection in the regional transmission plan for purposes of cost allocation and remaining selected," the commission said, noting that the NYISO Transmission Owners Agreement and the agreement between NYISO and the NYTOs on the Comprehensive Planning Process for Reliability Needs are less stringent than those in the development agreement

The NYTOs consist of Central Hudson Gas & Electric; Consolidated Edison; New York Power Authority; New York State Electric and Gas; Niagara Mohawk Power; Long Island Power Authority; Rochester Gas & Electric; and Orange and Rockland Utilities.

Compliance Filings

FERC also provided its clarification on alternatives to Attachments X and S in a concurrently issued order in which it accepted in part Order 1000 compliance filings NYISO made in March and September 2016. The commission accepted most of the ISO's Tariff revisions but rejected language it said was discriminatory or unjust (ER13-102, *et al.*).

It ordered the ISO to make changes in its proposed transmission interconnection procedures that it found unjust and unreasonable, including language on scheduling and definitions.

It also required the ISO to make changes in its proposed Operating Agreement regarding maintenance schedules, compliance with local reliability rules and investigations of equipment malfunctions.

The commission found "incorrect" the Tariff revision that said nothing in Attachment Y affects a TO's right to recover the costs of upgrades to its facilities regardless of whether the upgrade has been selected in the regional transmission plan for purposes of cost allocation.

"Pursuant to Order No. 1000, once NYISO selects a transmission project in the regional transmission plan for purposes of cost allocation, the regional cost allocation method set forth in Attachment Y of the [Tariff] applies, unless the project developer 'decline[s] to pursue regional cost allocation,'" the commission said.

NY Task Force Debates Carbon Pricing Models

Continued from page 27

Carron noted that "the concept is being discussed in the [Integrating Markets and Public Policy] process in New England," but he emphasized that he was speaking on behalf of National Grid and not the other consortium members that created it. (See *NECA Panelists Talk Carbon Pricing, Northern Pass*.)

"We share similar concerns to those presented last week by the city of New York, which is that this needs to be considered on an economy-wide scale," Carron said.

While the task force is only addressing how to harmonize wholesale energy markets with public policies in the energy sector, Carron said a wider approach could avoid creating perverse incentives and ensure that stakeholders understand how it is going to interact with other components of the state's energy plan.

"Doing some upfront work to establish the cost of carbon abatement in each sector would be a useful exercise for policymaking in all sectors and would inform the potential for leakage across sectors in this effort," Carron said.

Reeder said the DFCEM appeared similar to New York State Energy Research and Development Authority auction processes for obtaining renewable resources, in which one Tier 1 REC represents the energy production of 1 MWh.

"Ostensibly, that achieves a similar outcome if I think about the CES objective [of] around 50% renewables by date X," Reeder said. "So how would this interplay with what NYSERDA does right now? Is it a complement? Is it a supplement? Would it essentially obviate the need for NYSERDA to do what they do now?"

"I think that it might obviate the need," Carron said. "We should create a wholesale market solution that accomplishes as much of what we're setting out to do with public policy as possible."

Track 2 Issues and Scheduling

The task force also reviewed a plan for

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NYISO NEWS

Constitution Seeks FERC Rehearing of NY Permit Denial

By Michael Kuser

Constitution Pipeline last week asked FERC to reconsider a January order upholding a denial of the company's water permit application by New York environmental regulators, saying the commission "erred" in its interpretation of the federal Clean Water Act (CP18-5).

At issue is a proposed 124-mile natural gas pipeline originating in Pennsylvania that would deliver 650,000 dekatherms of gas per day into upstate New York.

Constitution last October petitioned the commission to rule that the New York State Department of Environmental Conservation (NYSDEC) had waived its authority under Section 401 of the Clean Water Act by failing to issue or deny a water quality certification within the one-year "reasonable period of time" stipulated by the act, despite the company's cycle of withdrawing and resubmitting the application.

But the commission disagreed, ruling last month "that once an application is withdrawn, no matter how formulaic or perfunctory the process of withdrawal and resubmission is, the refiling of an application restarts the one-year waiver period under Section 401(a)(1)."

Nonetheless, the commission said it continued to be concerned "that states and project sponsors that engage in repeated withdrawal and refiling of applications for water quality certifications are acting, in many cases, contrary to the public interest and to the spirit of the Clean Water Act by failing to provide reasonably expeditious state decisions." (See *FERC Upholds New York Denial of Constitution Pipeline*.)

Constitution's Feb. 12 petition calls on the commission "to curb this abuse of [the] legal process" in which the NYSDEC "has succeeded in delaying and frustrating the certification review process by claiming that Constitution's serial submissions entitle the agency to successive yearlong review periods."

"The commission erred in its interpretation of the 'reasonable period of time' in this case because the mechanical application of the final submission date of April 27, 2015, wrongfully allowed NYSDEC to exceed the maximum allowable period of time under the Clean Water Act," Constitution said.

The pipeline developer contends that the commission is fostering a regulatory scheme detrimental to the public interest and that its Jan. 11 order enables NYSDEC "to abdicate its responsibilities." The company noted that, except for the Clean Water Act approvals, the project is federally approved and its right of way has been optioned or acquired.

"The piping and equipment for this project have now been held in storage for over three years, and the pipeline remains fully contracted with long-term commitments from established natural gas producers currently operating in Pennsylvania," said the petition, which also requested expedited action by the commission to prevent further delay.

Constitution said its pipeline is "critical natural gas infrastructure needed to meet the natural gas demands of the Northeast United States — the current winter supply and pricing environment in New England making this point most clear and obvious." (See *FERC, RTOs: Grid Performed Better in Jan. Cold Snap vs. 2014*.)

In a proceeding related to the Millennium Pipeline, FERC last September ruled against the NYSDEC on a similar issue of timeliness, finding the agency had waived its authority to issue or deny a water quality certification for the project by failing to act within the one-year time frame required by the Clean Water Act (CP16-17). (See *Environmentalists Denounce FERC Millennium Pipeline Ruling*.)

NY Task Force Debates Carbon Pricing Models

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Track 2 of its work, which will deal with wholesale energy market mechanics — including "carbon leakage" and how to measure emissions — and interaction with other wholesale market processes.

The plan lays out Track 2 meetings from April to July before the suggested Aug. 1 deadline for draft recommendations. The joint staff will present frameworks for Track 2 issues of each meeting and also left some meeting dates open to resolve thorny issues — such as leakage — that may require additional discussion.

Representing New York City, Couch White attorney Kevin Lang expressed concern about transmission being slated for discussion on July 30, just two days before the deadline for draft recommendations.

"Waiting until the end of July to talk about transmission is way too late," Lang said.

IPPTF co-chair Nicole Bouchez, NYISO market design specialist, said the task force would consider earlier discussions on the subject but that it did not foresee the draft recommendations covering every issue.

In addition to transmission, Track 2 will also deal with leakage and resource shuffling; emission rates for generators; carbon shadow price; carbon charge implementation; emission rates for distributed energy resources and demand response; fuel blends; how much transparency is available; the mechanics of allocating carbon revenues; credit implications; capacity market implications; and bilateral arrangements.

#	Topic	Meeting Date
1	Leakage & Resource Shuffling	4/9
3	Emission Rates for Generators	5/7
4	Carbon shadow price	5/7
5	Carbon Charge Implementation	5/7
9	Emission Rates for DER and DR	5/7
14	Fuel Blends	5/7
18	How much transparency is available?	5/7
2A	Allocation of Carbon Revenues - mechanics	6/4
6	Credit Implications	7/9
7	Capacity Market Implications	7/9
8	Bilateral Arrangements	7/9
19	How this relates to transmission	7/30

2018 IPPTF meetings | *IPPTF*

The task force next meets Feb. 26 at NYISO headquarters.

NYISO NEWS

Business Issues Committee Briefs

Cold Snap Spikes Natural Gas Prices 136%

RENSSELAER, N.Y. — NYISO power prices surged to an average of $99.55/MWh in January, up 89% from December and 148% from the same month a year ago, Rana Mukerji, senior vice president for market structures, told the Business Issues Committee on Wednesday.

The ISO's year-to-date monthly energy prices averaged $101.54/MWh in January, an increase of 142% from a year earlier. Average sendout was 463 GWh/day, compared with 444 GWh/day in December and 431 GWh/day a year ago.

New York natural gas prices jumped 136% for the month, averaging $17.94/MMBtu at the Transco Z6 hub. Prices were up 369% from a year ago. Gas prices peaked at $140.06/MMBtu on Jan. 4, near the end of a two-week cold spell.

FERC on Jan. 12 granted a waiver request enabling the ISO to consider incremental energy and minimum generation offers that exceed $1,000/MWh if the generator is able to demonstrate such costs. The waiver covers Jan. 4 to Feb. 28. (See FERC Grants NYISO 'Cold Snap' Offer Cap Waiver.)

Distillate prices gained 28.2% year over year, with Jet Kerosene Gulf Coast averaging $14.47/MMBtu. Ultra Low Sulfur No. 2 Diesel NY Harbor averaged $14.83/MMBtu, up from $13.91/MMBtu in December.

The ISO's local reliability share was 59 cents/MWh, up from 9 cents/MWh the previous month, while the statewide share dropped 74 cents from the previous month to -$1.52/MWh. Total uplift costs were lower than in December.

Evaluation of Energy Market Offer Cap

Reviewing the Broader Regional Markets report, Mukerji highlighted NYISO's ongoing effort to resolve differences between regional offer caps that may interfere with economic- and reliability-driven interchange scheduling.

FERC this month accepted NYISO's Order 831 compliance filing, which requires the grid operator to cap incremental energy offers at the higher of $1,000/MWh or a resource's verified cost-based offer, which in turn are capped at $2,000/MWh when calculating locational-based marginal prices.

Mukerji also noted that FERC last month accepted the ISO's motion to terminate its obligation to submit annual informational filings on its implementation of interface pricing and congestion management and market-to-market coordination initiatives with its neighboring RTOs/ISOs.

The report also said the ISO has analyzed real-time commitment (RTC) and real-time dispatch (RTD) convergence and last month presented the Market Issues Working Group with recommendations to continue to aid the convergence this year. The ISO aims to improve modeling consistency between RTC and RTD and assess improvements to look-ahead evaluations to facilitate more efficient scheduling and price convergence.

NYISO also is working to clarify the minimum deliverability requirements for external capacity from PJM into the New York Installed Capacity (ICAP) market, Mukerji said. At the Jan. 17 BIC meeting, the ISO received approval for ICAP Manual revisions regarding the documentation requirements for capacity imports across the PJM AC ties, which will become effective May 1. (See "BIC Recommends ICAP Manual Revisions," NYISO Business Issues Committee Briefs: Jan. 17, 2018.)

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NYISO NEWS

BIC Briefs

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Day-Ahead Market Congestion Settlements

The BIC on Wednesday recommended that NYISO's Management Committee approve revisions to Attachment N of the Tariff that provide a methodology to allocate day-ahead market congestion rent shortfalls and surpluses resulting from changes in transmission facility availability to the responsible transmission owner.

Operations Analysis and Services Supervisor Tolu Dina explained how the methodology uses a *de minimis* threshold to determine circumstances when allocations to responsible TOs are not calculated.

The threshold applies to day-ahead constraint residuals (shortfalls and surpluses resulting from changes in transmission facility availability) that are less than $5,000, provided the sum of all such residuals below the threshold is not greater than $250,000 or 5% of the sum of all residuals for the month. Attachment N currently requires the ISO to conduct certain informational calculations once a year to help in assessing whether the *de minimis* threshold level presents any concerns.

External Capacity Rights

The BIC approved revisions to the ICAP Manual to better define the amount of capacity that can be imported into New York from neighboring control areas for the 2018/2019 capability year.

Josh Boles, the ISO's manager for ICAP operations, said the New York State Reliability Council regulates the amount of emergency assistance from neighboring RTOs and "we're only allowing imports up to a level where we would violate the one-day-in-10 criteria."

Alternative Methods for Determining LCRs

The BIC recommended the Management Committee approve revisions to the Market Administration and Control Area Services Tariff to establish an alternative method for calculating locational minimum installed capacity requirements.

Zachary Stines, associate market design specialist, presented NYISO's market design for determining locational capacity requirements (LCRs) for localities that minimize total cost of capacity at the level of excess condition while maintaining the reliability criterion and not exceeding transmission security limits.

The NYISO plan evaluates net energy and ancillary services revenue at different levels of installed capacity using data from the most recent of either the capability year after a quadrennial "demand curve reset" or the annual update.

The ISO has incorporated into the proposed Tariff revisions incremental revisions recommended by stakeholders at the Feb. 6 Installed Capacity Working Group/Market Issues Working Group meeting, Stines said.

BIC Rejects On Ramp/Off Ramp Changes

The BIC also voted against recommending that the Management Committee approve a market design proposal and related Tariff revisions for eliminating localities and revising the existing on ramp/off ramp rules to create a new locality.

Zachary Smith, manager of capacity market design, told the BIC that the proposed methodology is based on reliability planning principles developed to determine whether to create and eliminate localities.

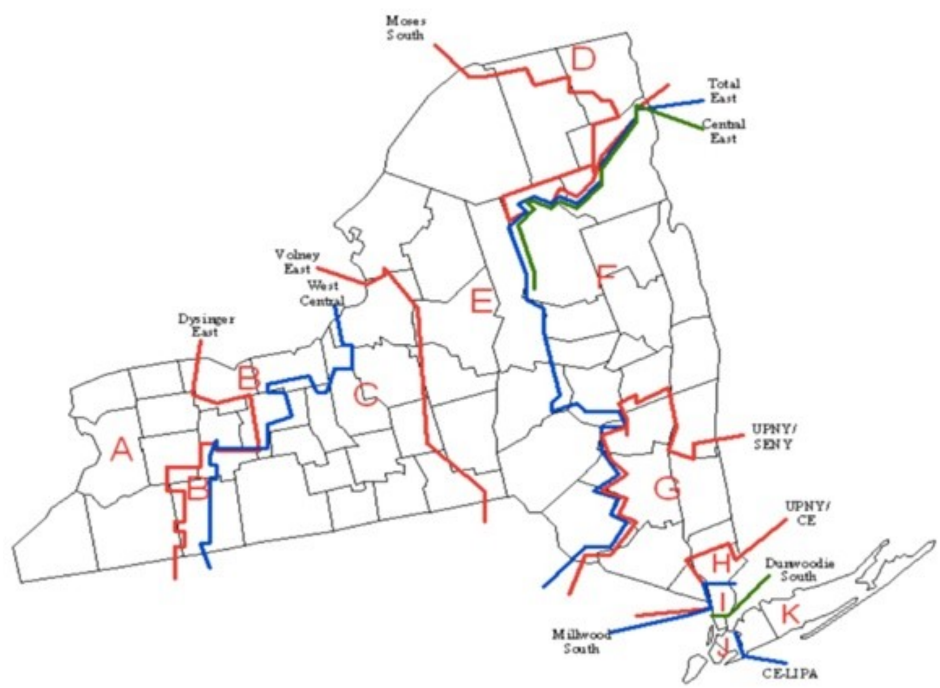
The proposed design was intended to make locality price signals direct investment to supply that provides the greatest reliability benefit.

Mark Younger of Hudson Energy Economics called the proposal "a flawed market design."

"It is attempting to use the transmission security test to estimate a resource adequacy requirement," Younger said. "The result of the NYISO's test as proposed is that it will understate the resource adequacy needs and would therefore result in creating localities too late and eliminating them too early."

Mukerji said that while the ISO has fully mapped out its resources and budget for the year, stakeholders could choose to juggle priorities in a related working group to make room for reworking the on ramp/off ramp proposal.

— Michael Kuser



NYISO locality boundaries | *NYISO*

PJM NEWS

PJM Board Punts Capacity Market Proposals to FERC

By Rory D. Sweeney

PJM's Board of Managers will ask FERC to choose between proposals by its staff and its Independent Market Monitor to insulate its capacity market from state-subsidized generation.

Rather than choose just one of the capacity reform plans on offer, the board instead voted Wednesday to direct PJM staff to file both the capacity repricing proposal it recommended and the MOPR-Ex proposal promoted by the Monitor.

"The board has decided that reform is necessary," CEO Andy Ott wrote in a letter to stakeholders Friday. "The board has chosen a path that will definitively move the policy question to FERC while proposing a process that maintains opportunities for active, continuing involvement from stakeholders."

Each proposal "represents a distinct, just and reasonable policy alternative to address the consequences of state intervention" in energy markets, Ott said.

"Deciding between these policy options requires a balancing of federal and state interests, raising questions of federalism and comity that have already presented themselves before the courts, including the U.S. Supreme Court."

The board didn't disclose its determination until Friday in order to develop an explanation for its decision. The vote came after a flurry of politicking over the past week from stakeholders, who sent seven letters to the board, almost all of which asking that the board not support PJM's plan. Exelon was ambivalent about the RTO's plan but asked that the board reject the Monitor's plan.

The decision moves PJM another step closer to culminating the work of the Capacity Construct/Public Policy Senior Task Force (CCPPSTF) that dominated stakeholder activity in 2017. Stakeholders were at one point considering 10 different proposals, but the field eventually narrowed to proposals from PJM and the Monitor.

PJM said its plan would accommodate generator offers from state-subsidized plants by allowing them to bid into capacity auctions but ensure they don't suppress competitive prices by removing those offers in a second "repricing" stage of the auction.

The Monitor's proposal, known as MOPR-Ex, would extend the RTO's minimum offer price rule (MOPR) to all units indefinitely, but in alternative versions it included carve-outs for states' renewable portfolios and public power self-supply. Stakeholders, who saw the Monitor proposal as having the least impact on the current construct, backed it all the way to the Markets and Reliability Committee, but all of its different versions stalled there last month after Ott announced he would be recommending the RTO's plan to the board no matter the outcome of the vote. (See "No Consensus on Capacity Revisions," *PJM MRC/MC Briefs: Jan. 25, 2018*.)

The board's decision represents a win for Monitor Joe Bowring, who had been maneuvering for months to navigate his proposal to stakeholder endorsement despite PJM's clear indication that it would not support the proposal.

The board directed staff "to present the advantages and tradeoffs associated with each policy approach," Ott said. Staff should make their preference known in the filing, but that "should the commission decide instead on a policy of mitigation, PJM believes MOPR-Ex would be effective in preserving competitive outcomes in PJM's markets."

The board also directed the filing to request "a time-bound settlement judge proceeding" after FERC chooses a proposal "with expectation that such a process will bring refinement, compromise and more consensus support for what ultimately will be presented to the commission later this year as a package of proposed rule changes."

The board confirmed that the upcoming Base Residual Auction in May will proceed under the current capacity auction rules.

FERC Orders New Rules for Supplemental Tx Projects in PJM

Continued from page 1

mission, it's needed; that regional needs are considered, that things aren't done individually and that the process is fair and transparent, and I think today's order is a part of that responsibility."

LaFleur is the only member remaining from the commission that issued a show cause order over the TOs' supplemental projects in August 2016, which followed a technical conference on the issue in 2015.

The order caused PJM's Transmission Replacement Processes Senior Task Force to go on a 10-month hiatus that, even after it ended, has been slow to progress as TOs remained reticent to discuss issues involved in the order. (See related story, *PJM TOs, Customers Await Ruling on Supplemental Projects*, p.36.)

Order 890 Inconsistencies

The TOs responded to the show cause order by contending they were already in compliance with Order 890 and proposing a new Tariff Attachment M-3 that they said spelled out their processes.

The commission agreed with the TOs' request to move the supplemental project language from PJM's Operating Agreement to Attachment M-3 but said the attachment fell far short of compliance with Order 890.

FERC found that TOs' handling of supplemental projects violates both the transparency and coordination principles of Order 890. It said that both the level of detail in the supporting information provided by TOs and the timing of providing that information — often either just before or during meetings to discuss those projects — fails to meet the order's requirements.

The commission cited Subregional RTEP Committee meetings on Dec. 1, 2016, in which AMP said TOs presented almost 100 transmission projects for stakeholder review, 80% of which were supplemental pro-

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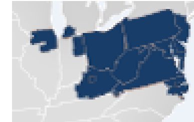

FirstEnergy Shutting down Unsold Coal Plant

By Rory D. Sweeney

Blocked by regulators from moving its ailing coal-fired Pleasants Power Station into the rate base of a subsidiary, FirstEnergy announced Friday it will shut the plant down instead. The company said in a news release that the 1,300-MW plant in Willow Island, W.Va., will be sold or closed on Jan. 1, 2019.

Pleasants Power Station

The plant has been at the center of a conflict between the company and state consumer advocates since Monongahela Power, a regulated FirstEnergy subsidiary, filed a plan in March 2017 seeking approval to acquire the station from another subsidiary, Allegheny Energy Supply. Mon Power selected the plant after issuing a request for proposals for generation.

FERC denied the request in January, ruling that the plant's selection resulted from an "overly narrow" solicitation that failed to consider competing resources. (See *FERC Blocks FirstEnergy Sale of Merchant Plant to Affiliate*.)

Soon thereafter, the West Virginia Public Service Commission approved the sale, but with restrictions that FirstEnergy felt were too onerous to proceed.

"Those conditions, combined with the FERC rejection, make the proposed transfer unworkable," the news release said.

FirstEnergy CEO Charles Jones said the company would continue to look for a buyer while it prepares for deactivation. The closure will affect 190 jobs, according to the release. Following the closure, the company will control 14,795 MW of generation from coal, nuclear, natural gas and renewables across Ohio, Pennsylvania, West Virginia, New Jersey, Virginia and Illinois.

The transfer to Mon Power was one of many avenues FirstEnergy has tried to offload its merchant generation. Jones has warned that its competitive generation subsidiary, FirstEnergy Solutions, will likely go bankrupt and has repeatedly confirmed plans to return FirstEnergy to regulated operations, where its investments will receive defined rates of return. (See *FirstEnergy Selling Merchant Fleet Despite NOPR*.)

PJM spokesman Ray Dotter on Monday said it's "way too soon to be able to say" whether Pleasants would be offered a reliability-must-run contract. "First, the reliability analysis must be completed. If the analysis indicates reliability issues, the owner could be requested to consider staying online until transmission upgrades were completed. If the owner agrees, it would go to the FERC to request an RMR rate."

Ex Parte Controversy

FERC's Jan. 12 ruling blocking the plant sale came after Commissioner Neil Chatterjee reported that lawyer William S. Scherman attempted to privately lobby him on FirstEnergy's behalf.

Chatterjee said Scherman called him the day before the ruling "indicating his concern that the commission would shortly issue an order adverse to the interests of Monongahela Power."

FERC Chairman Kevin McIntyre declined to say last month whether the commission would investigate who may have leaked information on the order to Scherman, who has represented FirstEnergy in the past. McIntyre called Scherman "a good friend" and "a terrific lawyer." (See *McIntyre: Won't Commit to Probe Leak to 'Good Friend'*.)

At a press conference following last week's commission meeting, McIntyre told reporters he had spoken with FERC General Counsel James Danly about the matter.

"I directed our general counsel to take the matter up with our designated agency ethics official to help us with two things," McIntyre said. "No. 1, to ensure that our annual ethics training properly address the issue of *ex parte* communication restrictions. Second, to ensure that it properly address the very important principle of ensuring no improper sharing of nonpublic information with regard to work in the commission. Those steps have been taken. I'm confident that they're the right steps."

Asked if it sent the right message for him to call Scherman a "friend," McIntyre responded: "It wasn't to send any signal along those lines. Really, just to ensure that our systems are properly functioning. I'm confident that they did in fact function properly."

Michael Brooks contributed to this article.

FERC Orders New Rules for Supplemental Tx Projects in PJM

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jects. Two of the projects presented were already complete, seven were under construction and 24 were already in the engineering phase, "at which point it is not possible for stakeholders to provide meaningful input," the commission said.

"The record in this proceeding indicates that the PJM transmission owners often provide models, criteria and assumptions as part of the supplemental project transmission planning process that are vague or incomplete and do not allow stakeholders 'to replicate the results of planning studies'" as required by Order 890, the commissioners wrote. "In addition, in some cases, the PJM transmission owners provide the models, criteria and assumptions to stakeholders at the same time as a proposed supplemental project, at which point that project is often at an advanced stage of development and stakeholder feedback is less likely to be meaningful or effective.

"As a result of these two factors — the quality of the models, criteria and assumptions the PJM transmission owners provide and the point in the transmission planning pro-

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PJM NEWS

FERC OKs OVEC Move to PJM

By Rory D. Sweeney

FERC dismissed concerns from several stakeholders last week in approving the Ohio Valley Electric Corp.'s integration into PJM (ER18-459, ER18-460).

The commission said OVEC and PJM had satisfied the Operating Agreement requirements for integrating the company, rejecting objections by stakeholders including American Municipal Power, the Ohio Consumers' Counsel and the Public Utilities Commission of Ohio. The protesters expressed concern that OVEC's integration will result in significant upgrade costs and increase the existing generation oversupply without providing more load for PJM generators to serve. (See *OVEC Integration not up for Debate, PJM Says*.)

The commission also accepted grandfathering of several power agreements and delivery commitments.

OVEC, which is headquartered in Piketon, Ohio, owns 2,200 MW of generation capacity but will have no load after a U.S. Department of Energy contract ends sometime before 2023. The company was created in 1952 to service a uranium enrichment plant near Piketon that ceased operations in 2001. The department ended the 2,000-MW contract in 2003 but maintains a load that can be 45 MW at its maximum but is generally less than 30 MW.

The company's two coal-fired generating plants — the 1.1-GW Kyger Creek in Cheshire, Ohio, and 1.3-GW Clifty Creek in Madison, Ind. — are already pseudo-tied into PJM, and its eight "sponsors" can sell their portions of the output into the RTO's markets. The generation would become internal to PJM following membership, eliminating the pseudo-ties.

The commission said it didn't buy members' arguments that a cost-benefit analysis should be required prior to integrating OVEC — a request which the OCC also made separately to PJM — because there's no precedent for it and the benefits to consumers from RTO membership "outweigh" integration costs. The commission said those benefits are "increased efficiency for transmission planning and generation investment, reduced transaction costs, improved grid reliability, limited discriminatory practices and improved market operations."

Clifty Creek power plant

It also said concerns about future costs aren't warranted because those costs will be allocated based on PJM's Tariff and OVEC's sponsor companies will continue to pay for OVEC's share. The order noted that PJM's studies indicated no transmission upgrades will be required to integrate OVEC. "With the exception of a single deliverability violation, which OVEC has committed to remedy, the existing equipment and facilities are adequate," the commission said.

PJM's Independent Market Monitor had raised concerns about OVEC's aging plants becoming eligible for reliability-must-run contracts if they decide to shut down, but the commission said the issue is beyond the scope of the integration request.

FERC Orders New Rules for Supplemental Tx Projects in PJM

Continued from page 33

cess at which they are provided — stakeholders frequently are not in a position to comment on the transmission planning studies or the resulting transmission needs before the PJM transmission owners take significant steps towards developing supplemental projects to address those needs," the commission wrote. "The fact that there may be multiple criteria and considerations underlying the need for a supplemental project does not prevent the PJM transmission owners from timely posting a thorough description of those criteria and considering stakeholder feedback before identifying a particular supplemental project. Similarly, the fact that those criteria may vary among the PJM transmission owners also does not prevent them from timely posting each transmission owner's different criteria."

The commissioners said the TOs' practice of simultaneously presenting both the problems and their proposed solutions discriminates against potentially better alternatives.

"The most obvious solution will not always be the best solution. In many cases, supplemental projects address facilities that have existed for several decades, during which time the topography of the electricity grid and the set of potential technologies available to address the underlying need may have changed considerably. As a result, rebuilding the facility that was the most obvious solution many years ago may no longer be the best solution today," the commission wrote.

FERC also sided with customers that the current process doesn't clearly define when they should receive critical information about criteria and proposals and when they can comment during the analysis and project development.

M-3 Revisions

The TOs did prevail in their request to move the procedures for planning supplemental projects from the OA — which requires a super-majority endorsement from PJM stakeholders to make changes — to Attachment M-3 of the Tariff. The TOs have exclusive filing rights under Section 205 of the Federal Power Act to make changes in Attachment M-3; to make any changes, stakeholders would need the PJM Board of Managers to file a complaint under Section 206.

However, the commission also ordered revisions to the new attachment, saying it "duplicates and otherwise relies heavily on the provisions … that we found above to be unjust and unreasonable."

The commission ordered the TOs to revise M-3 and to hold three meetings on each

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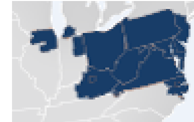
PJM NEWS



MRC Preview

Below is a summary of the issues scheduled to be brought to a vote at the PJM Markets and Reliability Committee on Thursday. (The scheduled Members Committee meeting was canceled.) Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be in Wilmington, Del., covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

2. PJM Manuals (9:10-9:30)

Members will be asked to endorse the following proposed manual changes:

A. Manual 2: Transmission Service Request. Revisions developed to align manual with Tariff changes endorsed at the Dec. 21 meeting to revise the process for analyzing transmission service requests. The initial study is replaced by the firm transmission feasibility study.

B. Manual 11: Energy & Ancillary Services. Clarifies the energy-offer verification process for demand-side bids, including caps on price-sensitive demand bids; reverses prior change to pre-emergency and emergency demand response because they are outside the scope of FERC Order 831.

C. Manual 14D: Generator Operational Requirements. Clarifies information requirements and submission deadlines for generation transfers. (See "Owner Transfer Rules Revision," *PJM Operating Committee Briefs: Dec. 12, 2017*.)

D. Manual 18: PJM Capacity Market. Revisions developed in response to a FERC order on rules for pseudo-tie requirements and a transition period for existing pseudo-ties (ER17-1138). (See *FERC OKs Change to MISO, PJM Pseudo-Tie Rules*.)

3. Tariff Revisions to Address Overlapping Congestion (9:30-9:45)

Members will be asked to endorse proposed Tariff and Operating Agreement changes to address overlapping congestion. PJM and MISO have been working to remove duplicative congestion charges and have developed a two-phase plan to eliminate them. These changes encompass the second phase. (See *MISO, PJM Pursue Pseudo-Tie Double-Charge Relief*.)

4. Summer-Only Demand Response Senior Task Force Charter (SODRSTF) (9:45-9:55)

Members will be asked to endorse a draft charter for the SODRSTF. The task force, which was developed to consider ways to take advantage of excess summer-only resources, has met several times. (See *Stakeholders Seek Load Discussion in PJM DR Task Force*.)

5. Sunsetting Senior Task Forces (9:55-10:15)

Members will be asked to sunset the Underperformance Risk Management Senior Task Force (URMSTF) and the Regulation Market Issues Senior Task Force (RMISTF). The URMSTF developed proposals on underperformance risk management, which failed to receive MRC stakeholder endorsement, and changes to external capacity performance requirements, which were endorsed. The RMISTF resulted in a new regulation signal being implemented, along with a package of regulation procedure and requirement changes. (See *PJM Regulation Compensation Changes Cleared over Opposition*.)

— Rory D. Sweeney

FERC Orders New Rules for Supplemental Tx Projects in PJM

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proposed supplemental project: the first to discuss "the models, criteria and assumptions" used to plan supplemental projects, the second to address the needs identified and the third to discuss the solutions proposed to meet the needs.

The revised M-3 must spell out a minimum number of days between each meeting, deadlines for posting the meeting materials beforehand and time frames for stakeholders to provide comments after meetings, the commission said.

"We also find that this additional transparency will help mitigate concerns that supplemental projects may be structured to avoid or replace regional transmission projects that would otherwise be subject to competitive transmission development under Order No. 1000," the commission wrote.

FERC also ordered the TOs to detail what dispute resolution they plan to use, as the previous rules relied on the procedures in the OA. The commission also ordered PJM to make changes to its OA to ensure consistency with M-3 and compliance with Order 890. PJM and the TOs have 30 days to file the required revisions.

The commission shot down proposals by AMP and Old Dominion Electric Cooperative to require TOs to respond to stakeholder comments, greater PJM involvement in planning for and selecting certain supplemental projects, and PJM review and approval of TOs' local transmission plans.

'Encouraged'

AMP's Ed Tatum said his company is still reviewing the order but is "encouraged by what we have seen so far."

He pointed to the commission's affirmations on transparency and coordination principles from Order 890, the need for meaningful input from consumers and the opportunity to replicate TO results.

"Since October 2016, the PJM transmission owners have been unwilling to move from their litigation position and fully engage absent an order," he said. "Now that we have an order with clear direction, we are ready to roll up our sleeves and work with PJM and the transmission owners to implement the order and make sure consumers are getting the transmission system they need at right price."

Representatives from Exelon and Public Service Electric and Gas did not response to requests for comment in time for publication.

Chairman Kevin McIntyre did not participate in the ruling.

PJM NEWS

In case you missed it ...

(Originally published Feb. 14)

PJM TOs, Customers Await Ruling on Supplemental Projects

By Rory D. Sweeney

PJM's Transmission Replacement Processes Senior Task Force stands to become much more engaged now that FERC has ruled on a show-cause order that hampered the task force's progress for about a year and a half. | © *RTO Insider*

As far as PJM transmission owners are concerned, the customer doesn't always know best. They lack the institutional knowledge of the TOs, who have been operating their systems for decades and are responsible for their performance.

PJM transmission customers agree that they don't have the information the TOs possess. But some are trying to change that imbalance, saying they are no longer willing to pay for replacing an aging infrastructure system without assuring themselves that the spending is necessary.

How much more information the TOs will be required to share could be decided at tomorrow's FERC meeting. The commission is scheduled to release a decision on its 2016 show cause order that questioned whether TOs' procedures for planning supplemental projects provided stakeholders opportunity for "early and meaningful input and participation," as required by Order 890 (EL16-71). (See *FERC Orders PJM TOs to Change Rules on Supplemental Projects*.)

The commission is also scheduled to address the TOs' proposed Tariff Attachment M-3, which they developed to codify the "additional detail and transparency regarding the process for planning supplemental projects" that they've agreed to (ER17-179). (See *PJM Demands Agreement on Tx Replacement Definitions*.)

RTOs Provide Customer Forum

For most of their existence, TOs have had only to persuade state and federal regulators that their infrastructure plans were necessary, under a monopoly structure that entitled them to cost recovery and a margin of profit. The development of RTOs and ISOs has given their customers a forum to voice concerns and seek influence over transmission planning.

In PJM, American Municipal Power has made controlling its transmission costs a primary focus. Supported by several other RTO members — fellow transmission customers, state consumer advocates and merchant transmission developers — AMP has pushed the issue to confrontation on multiple fronts, including a stakeholder task force focused on end-of-life issues for transmission infrastructure. (See *AMP Presses AEP, PSE&G on Transmission Projects*.)

The Transmission Replacement Process Senior Task Force (TRPSTF) became a flashpoint almost as soon as it was proposed in January 2016. TOs argue that PJM and FERC rules give them sole discretion over how to maintain their assets — including when and how to replace them. The task force went into a 10-month hiatus after FERC issued its show cause order but reconvened after PJM stakeholders reinstated it last year.

More Transparency Sought

AMP and Old Dominion Electric Cooperative said they have been concerned about transparency in the planning process for quite some time.

"I don't know if we had a big bang or if we had a slow burn," AMP's Ed Tatum said in an interview with *RTO Insider*. "We just kept asking more questions. … That gave us some traction to continue to ask questions."

Both sides acknowledge that infrastructure, at some point, needs to be replaced. But the customers argue they aren't provided enough information to independently evaluate whether proposed replacements are necessary or excessive. "I feel there should be adequate information for us to determine what is needed," Tatum said.

AMP and ODEC argue that TOs are incentivized by their formula rates to build as much as possible and that regulators' oversight is not adequate to corral the impulse.

"To me, it's more of a check and a balance: Before they start replacing something, does it make sense?" ODEC's Mark Ringhausen said. "Maybe that's a concern that some of the TOs have: [that customers will] figure out that we're replacing more facilities than they really need to."

They point to a sudden rise in supplemental

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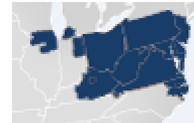
PJM NEWS



In case you missed it ...

(Originally published Feb. 14)

PJM TOs, Customers Await Ruling on Supplemental Projects

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transmission projects, which are projects developed by TOs for their own transmission zones to address their own planning needs. They don't have to address any PJM criteria, nor do they require the RTO's sign-off to begin work.

Through 2012, according to a study done for AMP, PJM had planned or in service \$21.3 billion in baseline and network upgrades — which are subject to detailed review by the RTO — versus \$6.8 billion of transmission-owner identified (TOI) and supplemental projects. Since 2012, the \$11.6 billion in baseline and network upgrades have been exceeded by \$12.7 billion of TOI/supplemental projects.

"There are more projects outside of the PJM planning process than there are inside," Tatum said.

"Of the 270 supplemental projects in 2017, when presented at their respective first reads [at Subregional RTEP Committee meetings], 181 of the projects were already in a stage of development ranging from engineering to 100% complete, with five projects already in service at their first reads," the customers said in a 61-page recounting of their arguments filed on Tuesday. "At the second read, 205 out of 270 proposed supplemental projects were beyond the conceptual/scoping development phase, with nine already in service. Said another way, 76% of supplemental projects were presented to stakeholders in the SRRTEP meetings at a stage of development where meaningful input is unfeasible at best."

Customers believe TOs have used these opportunities to bypass the stakeholder process and go straight to state and federal commissions, where they say they maintain longstanding political influence, as their best bets for revenue growth. (See *Report Decries Rising PJM Tx Costs; Seeks Project Transparency*.)

"I think it's pretty simple economics. They're not making a whole lot of money on generation right now, and they're getting [returns on equity] on transmission in the 10 to 12% [range]. We don't blame them," AMP General Counsel Lisa McAlister said.

"Part of the reason why [customer input is] so important is because there's not a lot of other regulatory oversight, and when it does happen, it's too late in the process to be meaningful," said McAlister, who signed AMP's filing. "There aren't a whole lot of other stopgaps to help."

In its filing Tuesday, which asked the commission to reject Attachment M-3 and order further changes to achieve compliance with Order 890, the customers said FERC should require TOs and PJM to:

- Record and post all questions and answers from proposal reviews;
- Provide the power flow study details, including a description of the violations or issue identified;
- Provide more detailed descriptions of the proposed facilities, including descriptions and costs of the assets being retired, installed or replaced; and
- Provide adequate time for review and analysis.

PJM's subregional transmission expansion plan process "has no provision to validate a TO's need for supplemental projects nor the prudency of the project," the coalition said.

TOs' Response

Gloria Godson | © *RTO Insider*

The customers' requests ignore PJM's function on supplemental projects, says Exelon's Gloria Godson.

"PJM's process is a planning process, not a prudency review," Godson said in an interview with *RTO Insider*. The correct venue for cost complaints is at FERC and state commissions, not PJM, she said.

To best understand the conflict, Godson said, think of TOs as car manufacturers and their networks as their own unique vehicle that they lease to customers. Customers get to use the car for their needs and must pay for improvements and maintenance, but ownership, knowledge about and ultimate responsibility for it remain with the manufacturer.

Customers want to understand the car's engineering so well that they can independently confirm the need for the expenses the owners want them to incur. But the owners fear customers are more focused on cost because they're not on the hook for the car's reliability.

PJM, in Godson's analogy, is the company that builds and maintains roads. But the RTO can't tell TOs what tires to install on the car or when to replace the radio, she said, any more than it can tell TOs how much that work should cost.

In a combined statement to *RTO Insider*, PPL, Public Service Electric and Gas (PSE&G), Exelon and Duquesne Light said replacement costs have increased in response to new obligations, such as higher security demands and increased efficiency and reliability standards.

"Shared final decision-making with a diverse set of stakeholders each with differing priorities would negatively impact the safety, reliability, security and efficiency of the transmission network. It would also lead to lack of clarity as to who has the responsibility for the impact of adverse events," the TOs said.

Order 890, the TOs said in their October 2016 response to the order to show cause, "affirmed that the ultimate responsibility for planning remains with transmission providers and that it was not requiring transmission providers to engage customers in the transmission planning process on a 'co-equal basis.'"

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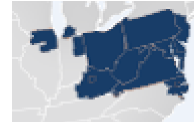

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PJM TOs, Customers Await Ruling on Supplemental Projects

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Godson pointed to her experience at Potomac Electric Power Co. (Pepco) with the failed Mid-Atlantic Power Pathway project as an example of regulators' exercise of cost discipline. Pepco attempted to recover $87.5 million in costs after the project was canceled by PJM, but intervenors protested and FERC eventually approved a $80.5 million settlement (ER13-607).

No Bright Line

It's not possible, TOs say, to develop a standardized way for customers to replicate the analysis that they would be able to endorse because it would require modeling so detailed and exact — on variables ranging from terrain and weather to population density, local regulations and load types — as to be impractical, along with institutional knowledge that they say only exists at the TO.

"There is no bright-line criteria for determining when an asset should be replaced, as it is based upon a variety of factors that require engineering and operational judgement," the statement said.

"A company may be willing to take a different type of risk in a rural area than they may be willing to take in Washington, D.C., for example," Godson added. "That goes from one TO to another, so it's ... not possible to have a cookie-cutter approach to system design. ... My question would be, for what basis? PSE&G knows their system better than anybody can. ... This is what they do for breakfast, lunch and dinner."

More can be Done, Customers Say

Customers acknowledge the issues but say there's more that can be done.

"There's judgment to this, but those are discussions that need to happen," Ringhausen said. "They need to present us enough information that we can understand their criteria."

"One of my large concerns with this is [the industry] creating the exact same situation we're in now for the next generation down the road," AMP's Ryan Dolan said. The transmission infrastructure was largely built at the same time, and TOs are "in a mad rush" to replace everything at the same time. Dolan argues that with some foresight and consideration, the replacements, and their costs, could be rolled out over time.

"Should we have a long, sustained capital investment?" he asked.

"TOs don't have anything that predicts the longevity of assets. ... Age is simply a bucketing mechanism, but whether and when an asset is actually replaced depends on the condition of that asset," Godson responded. "So, you may have a transformer that is relatively newer, but if it begins to [break down], you cannot defer maintenance [just] because it's not old enough. Conversely, there are assets that are 70 years old and still going strong. So it depends on the condition and performance of the asset."

While TOs' primary strategy is monitoring and replacing based on condition and performance, there are some times when equipment targeted for replacement can be addressed while repairs are being made to infrastructure nearby.

Improvements

Ed Tatum | © RTO Insider

TOs argue they have worked to improve information sharing in the monthly meetings that focus on PJM's Regional Transmission Expansion Plan, as documented in Attachment M-3. "The PJM process is far and away the most transparent of any process in the country," Godson said.

Tatum contends the sides are "fairly close" and that a solution to the dispute "doesn't need a quantum shift."

The TOs disagree with the magnitude of the change they say AMP and its allies are requesting.

"AMP's proposal that PJM and the PJM stakeholders take over the TOs' responsibility for asset replacement and managing the supplemental project planning process violates the [Consolidated Transmission Owners Agreement] and would breach a fundamental contract that forms the basis upon which TOs joined PJM," the TOs said. "PJM does not have the expertise, experience or resources to take over the TOs' asset management function. PJM has stated repeatedly that they do not consider this an appropriate role for PJM."

FERC & FEDERAL NEWS

FERC Finalizes Frequency Response Requirement

By Rich Heidorn Jr.

New generators seeking interconnections must be equipped to provide primary frequency response, FERC ruled Thursday (RM16-6).

The commission said the requirement that generators have governors or other equipment to respond automatically to frequency disturbances must be included in the *pro forma* generator interconnection agreements (GIAs) for both large (20 MW+) and small generators.

The rules will apply to new generation and existing generators that seek a new interconnection agreement because of "material modifications" to their facilities. The commission declined to order existing generators to retrofit their facilities to provide the service, saying it would be "prohibitively expensive" for some.

The final rule makes only small changes from the commission's November 2016 Notice of Proposed Rulemaking, which cited concerns by NERC and others that frequency response has declined with the loss of traditional synchronous generation and the increase in asynchronous renewables. (See *FERC: Renewables Must Provide Frequency Response*.)

The commission cited a 2010 NERC survey that found only 30% of generators in the Eastern Interconnection provided primary frequency response and that only 10% provided "sustained" response. The commission said the existing *pro forma* large GIA — which required primary frequency response from only synchronous generating facilities — does not reflect technological advances allowing nonsynchronous generation to provide the service.

The commission set operating requirements of a maximum droop setting of 5% and a deadband setting of ±0.036 Hz.

"We find that the establishment of minimum uniform operating requirements for all newly interconnecting generating facilities is preferable to the fragmented and inconsistent primary frequency response settings currently in place throughout the Eastern and Western Interconnections," FERC said. ERCOT already has minimum frequency response requirements, FERC noted.

Wind farm outside Palm Springs, Calif. New wind farms must be able to provide primary frequency response under a FERC rule approved Thursday. | *© RTO Insider*

FERC agreed with recommendations by the Edison Electric Institute and the Western Interconnection Regional Advisory Body that it modify the rule to explicitly prohibit interconnection customers from blocking their governors' ability to respond to frequency deviations.

"One of the commission's concerns with the current lack of clear, uniform primary frequency response requirements is NERC's finding indicating that a number of generator owners/operators have implemented operating settings that have effectively removed the availability of their generating facilities from providing timely and sustained primary frequency response (e.g., wide deadband settings, uncoordinated plant-level controls). The reforms adopted in this final rule, to be applied uniformly to new generating facilities, are intended to eliminate these practices."

The commission disagreed with the National Rural Electric Cooperative Association's (NRECA) contention that the rule is premature, saying "adopting these requirements now is more prudent than waiting until the lack of primary frequency response undermines grid reliability, a point acknowledged by NERC's Essential Reliability Services Task Force."

Headroom, Compensation

The commission rejected EEI's proposal that generators be required to maintain headroom — allowing them to increase output in response to low frequency — and receive compensation for doing so. "If future conditions necessitate a headroom requirement, we will then consider any appropriate compensation," it said.

FERC also said it would consider on a case-by-case basis requests from transmission providers seeking to impose a headroom requirement "in a particular factual circumstance" that includes a compensation mechanism.

The commission said compensation is not necessary because "the cost of installing, maintaining and operating a governor or equivalent controls is minimal." FERC estimated the cost of adding governors to new wind and solar generators would average $3,300/MW, about 0.2% of total capital costs for wind and solar.

FERC also rejected requests that it order compensation for traditional generators that provide inertial response. "No commenter asserts that inertial response trends on the Eastern and Western Interconnections are approaching levels that could threaten reliability. In addition, because inertial response is provided automatically by the rotating mass of synchronous machines as system frequency deviates and is not controllable, synchronous generating facilities do not incur additional incremental costs to provide inertial response," the commission said.

Exceptions and Accommodations

The commission exempted or offered accommodations to some classes of resources:

- Combined heat and power (CHP) generators that are sized to serve onsite load and have no ability to export power to the grid will be exempt from the operating requirements but must install a governor "in the event that there is an increased need in the future for primary frequency response capability."

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FERC & FEDERAL NEWS

Ameren Rate Incentive Rejected by FERC

FERC last week declined to grant Ameren additional transmission incentive rates for portions of the company's 500-mile Grand Rivers project in Illinois and Missouri.

Ameren sought a 100-basis-point incentive adder for the return on equity for the Illinois Rivers and Mark Twain components of the project, which is intended to create a continuous 345-kV path from Iowa to Indiana. The company also requested authorization to assign the incentive to any affiliate that undertakes the development, construction or ownership of those portions of the project.

The commission said the segments were already too far developed to be considered risky enough for incentive rate treatment (ER18-463).

"We find that, due to the late stage of … development, including the substantial completion of the Illinois Rivers component, Ameren Transmission has failed to demonstrate that the remaining risks and challenges associated with the components warrant the requested ROE incentive," the commission sad. "A project that is further along in construction and thus closer to completion typically faces fewer remaining risks and challenges, and we find that is true here."

FERC agreed with the contention by the Organization of MISO States and the Missouri Public Service Commission that Ameren had already spent 77% of its cost estimate on the two lines when it asked for the rate incentive in mid-December, when permitting risks were minimal and already covered by a previously approved abandonment incentive. Ameren had argued that the two lines face "unprecedented" risks that are not covered by its other rate incentives.

The commission has previously granted several incentives for the Grand Rivers Project, including 100% construction-work-in-progress recovery, abandoned-plant recovery, a hypothetical capital structure and the authority to assign incentives to affiliated entities.

| Ameren

— Amanda Durish Cook

FERC Finalizes Frequency Response Requirement

Continued from page 39

- Energy storage will only be required to provide frequency response within specified operating ranges representing minimum and maximum states of charge. The commission said the accommodation would prevent the premature degradation of storage resources.
- Distributed energy resources will be required to provide frequency response only when they are allowed to ride through disturbances, the commission said in response to Xcel Energy's concern that dynamic frequency response at the distribution level can interfere with anti-islanding protections. The rule does "not supersede a generating facility's ride-through settings or require an interconnection customer to override anti-islanding protection or any protective relaying that has been set to disconnect the generating facility during certain abnormal system conditions," the commission said.
- Nuclear generators are exempt from the rule because their licenses with the Nuclear Regulatory Commission often restrict providing frequency response.

No Exemption for Wind, Small Generators

Wind generation must comply with the requirement, the commission said, rejecting an exemption request by Sunflower Electric Power and Mid-Kansas Electric.

"Unlike certain CHP or nuclear generating facilities, the record does not indicate that there is an economic, technical or regulatory basis for a generic exemption for newly interconnecting wind generating facilities," FERC said. "In particular, we are persuaded by [the American Wind Energy Association's] assertion that the proposed primary frequency response capability requirements can be met at low cost for new wind projects, and that newly interconnecting wind facilities should not have difficulty complying."

Small generators also will not be exempt. The commission said the rule will not result in "unduly burdensome" costs or create a barrier to entry, noting that PJM has not seen a decrease in small generator interconnections since it required nonsynchronous generation to install enhanced inverters with frequency response capability. "We are persuaded by commenter assertions that that small generating facilities are making up a growing percentage of the generation resource mix, and that as the market penetration of small generating facilities increases, there will be a growing need for primary frequency response from these generating facilities," FERC said.

The commission rejected NRECA's request that individual balancing authorities be permitted to seek waivers from the rule but agreed that "unique circumstances or needs of some individual regions or areas may warrant different operating requirements." FERC said it would consider variations based on Regional Entity reliability requirements; variations that are "consistent with or superior to" the final rule; and "independent entity variations" filed by RTOs and ISOs.

The revised GIAs are due 70 days after publication of the rule in the *Federal Register*.

FERC & FEDERAL NEWS

Michigan Dam Ordered Shut over Safety Breaches

By Amanda Durish Cook

FERC last week ordered the shutdown of a Michigan hydroelectric project over longtime safety violations — the most significant of which relate to inadequate spillway capacity.

The commission will revoke the license for Boyce Hydro's 4.8-MW Edenville Dam in northern Michigan on March 1 following its Feb. 15 cease generation order and denial of the company's request for rehearing on the issue (10808-058).

FERC dismissed Boyce's arguments that the commission didn't consider corrective measures the dam had already taken; that it doesn't have authority to order a dam to shut down; and that the cease generation order was arbitrary and capricious. FERC has been threatening to close Edenville since late last spring.

The commission last month gave Boyce until March 1 to correct violations, some of which that have persisted since 2004, including:

- Failing to increase spillway capacity to address the increased likelihood of more frequent flooding;
- Performing unauthorized dam repairs and excavation;
- Neglecting to file a public safety plan or follow its own water monitoring plan; and
- Failing to acquire all property rights and to construct required recreation facilities near the dam.

FERC has repeatedly told Boyce to construct two auxiliary spillways to reduce the risk of flooding, "a grave danger to the public," the commission wrote.

"Boyce Hydro's license includes terms and conditions concerning dam safety, property rights, water quality, public recreation and safety, and other areas of public concern," the commission said. "Boyce Hydro has a long history of noncompliance with those terms and conditions … [and] failed to comply … except for the obligations to acquire and document certain property rights (although the lack of designs for the new and revised spillways makes it difficult to determine if it has acquired all necessary property rights)."

The commission in January granted Boyce a temporary stay of shutdown until the beginning of March so the company can use the dam's powerhouse to pass flows to alleviate ice formation on spillway gates during winter. (See *Michigan Dam Faces Shutdown over Longtime Safety Concerns*.)

FERC said Edenville's current spillway can only currently handle 50% of a probable maximum flood.

The commission ordered Boyce last year to file plans to construct spillways and provide public access and recreational facilities by late 2017, but the filings never materialized, it said. Although Boyce had hired an engineering firm to design a new spillway and promised to create an escrow account for 50% of its gross revenues to fund construction, FERC found those plans insufficient, saying that it would take the company two years to save enough money to fund spillway construction.

"Given that the public has already been at risk for more than 13 years due to the licensee's refusal to remediate the project spillways, we cannot accept a proposal that will perpetuate the problem even longer," FERC said.

The commission expressed disbelief that Boyce's lengthy history of noncooperation would change now.

"After weighing the relevant factors, commission staff determined that the violations required prompt action and that the licensee's persistent pattern of noncompliance provided strong evidence that it would not make serious efforts to come into compliance absent an order disrupting its operation," the commission wrote.

FERC said it didn't take the economic impacts of a shutdown lightly but said the move is "a situation of Boyce Hydro's own making."

Boyce can seek a rehearing of the order before a FERC administrative law judge within 30 days.

ITC Subsidiary Gets OK to Buy Michigan Tx Assets

FERC last week authorized an ITC Holdings subsidiary to purchase transmission assets from a small southwestern Michigan city.

The ruling authorizes Michigan Electric Transmission Co. to spend $201,206 to buy transmission assets at the Black River Substation from the City of Holland Board of Public Works (EC18-21). The assets include surge arrestors, relay panels, circuit breakers, backup relays and disconnect switches that Michigan Electric plans to use in its transmission operations.

The commission said the acquisition was consistent with the public interest and won't hinder competition in the area.

Michigan Electric has also pledged to hold all transmission customers harmless from any transaction costs for five years.

"The proposed transaction does not involve any change in ownership or control of any generating facilities. Accordingly, the proposed transaction will not have any impact on concentration in any relevant market," FERC said. The commission also said that prior experience suggests that sales involving only the transfer of transmission facilities are unlikely to result in uncompetitive activity.

— Amanda Durish Cook

| *ITC Holdings*

Con Edison Q4 Earnings Up 144%

Consolidated Edison's fourth-quarter net income increased 144% to $505 million ($1.63/share) from $207 million ($0.68/share) in 2016, the company said last week.

Total revenue for the quarter increased 9.38% to $2.961 billion.

The company reported 2017 net income of $1.525 billion ($4.97/share), compared with $1.245 million ($4.15/ share) in 2016. Total revenue was down slightly in 2017 but remained above $12 billion.

Con Ed said its adjusted earnings for 2017 excluded the remeasurement of deferred tax assets and liabilities upon enactment of the federal Tax Cuts and Jobs Act, the effects of the gain on the sale of a solar electric production project, and the net mark-to-market of Con Edison's clean energy businesses.

The company's earnings presentation showed the new law reduced the net deferred tax liabilities for its Con Ed of New York, Orange and Rockland Utilities and Rockland Electric subsidiaries by more than $5 billion collectively.

Con Ed plans to meet its 2018 capital requirements through internally generated funds and the issuance of securities. The company's plans include issuing between $1.3 billion and $1.8 billion of long-term debt at its utilities and additional debt secured by its renewable electric production projects.

The company also plans to issue up to $450 million of common equity in addition to equity under its dividend reinvestment, employee stock purchase and long-term incentive plans. The plans do not reflect the provision to utility customers of any tax law benefits that may be required by the New York Public Service Commission or the New Jersey Board of Public Utilities.

— Michael Kuser

COMPANY BRIEFS

3 Utilities Interested In Buying Santee Cooper

NextEra Energy and Pacolet Milliken are both willing to pay $10 billion for Santee Cooper's electric business, a source told *The Post and Courier*. A third utility that the source wouldn't identify is willing to manage the troubled utility and work toward buying it.

Santee Cooper, which is owned by the state of South Carolina, was a partner with SCANA in a failed attempt to expand the V.C. Summer nuclear plant. Dominion Energy has offered to buy SCANA for $14.6 billion in stock and assumed debt.

Meanwhile, on Feb. 15, the South Carolina Senate voted 35-0 to give the Public Service Commission until the end of the year to rule on Dominion's purchase of SCANA; the South Carolina House of Representatives voted 108-1 to fire the seven members of the PSC over the next two years.

More: *The Post and Courier*; *The Post and Courier*

MidAmerican Brings on 2 Wind Farms Totaling 338 MW

MidAmerican Energy said two wind farms with a capacity of 338 MW have begun operations in Iowa. The Beaver Creek and Prairie wind farms are part of the utility's $3.6 billion, 2,000-MW Wind XI project, which it expects to complete by the end of 2019.

MidAmerican expects renewables to produce 95% of the power for its Iowa retail customers by 2021.

More: *The Gazette*

FERC Accepts Uniper Subsidiary's Change of Status

FERC on Feb. 15 issued an order accepting Uniper Global Commodities North America's (UGCNA) change of status and directed the energy and freight trader to revise its market-based rate tariff to reflect its Category 2 seller status in the Northeast region within 30 days.

The change is related to German energy group E.ON's Jan. 1, 2016, spin-off of 53.35% of UCGNA's parent, Uniper, which, in addition to owning an energy trading business, owns power plants in Europe.

E.ON tendered its remaining 46.65% stake in Uniper to Finnish energy company Fortum for $4.5 billion in January, but that was not addressed in the order.

More: *ER16-262*

Sierra Club, Talen Reach Settlement to Close Brunner Island

Brunner Island power plant | *Talen Energy*

The Sierra Club on Feb. 14 said that it had reached a settlement with Talen Energy under which the company will phase out coal burning at its Brunner Island power plant in York County, Pa.

The settlement calls for Talen to stop burning coal at the plant from May to September with some limited exceptions by 2023 and year-round by 2028.

The Sierra Club and Talen intend to execute the settlement through a court-enforceable consent decree they will file after a required 90-day waiting period that starts with a Notice of Intent to sue, which the Sierra Club served.

More: *Sierra Club*

Former PJM CEO Boston Joins Dewberry Board

Former PJM CEO Terry Boston has joined the board of directors of Dewberry, an engineering firm based in Fairfax, Va.

Boston, who left PJM at the end of 2015 after seven years leading the RTO, runs a consulting firm that specializes in power supply planning, cybersecurity, transmission, and renewables development and storage. He is a 2017 presidential appointee to the National Infrastructure Advisory Council and a past president of GO15, an association of the world's largest power grid operators. Boston spent the majority of his career at the Tennessee Valley Authority, where he worked for many years prior to joining PJM.

"Terry began making a difference in the way we think about Dewberry's future from the first time we met," said Dewberry Executive Chairman Barry K. Dewberry. "Terry will clearly be a force as a director."

More: *Dewberry*

FEDERAL BRIEFS

Judge Orders DOE to Implement Obama Energy-Use Standards

A federal judge in San Francisco on Feb. 15 ordered the Department of Energy to implement standards adopted in the final days of the Obama administration to limit energy use by portable air conditioners, air compressors, commercial packaged boilers and uninterruptable power supplies.

U.S. District Judge Vince Chhabria issued the order in two cases involving lawsuits against the department, one filed by 11 states and New York City and the other by environmental groups.

The order requires the department to publish the standards within 28 days. Once published, they become legally enforceable.

More: *The Associated Press*

DOE Provides $6.5 Million to 9 Coal Technology Projects

The Department of Energy on Feb. 15 said its Office of Fossil Energy and National Energy Technology Laboratory have selected nine projects to receive approximately $6.5 million in the first stage of a $50 million funding opportunity for potentially transformational coal technologies.

The department said the selected projects have demonstrated technical success at the small-scale pilot stage of development and some are ready to proceed to the large-scale pilot stage.

The funding opportunity is meant to produce two large-scale pilots. Project sponsors must bear some of the cost.

More: *Department of Energy*

EPA Retracts 'Blanket Waiver' Claim About Pruitt's Flying

EPA on Wednesday retracted its claim that Administrator Scott Pruitt has a "blanket waiver" to travel first class on all the flights he takes, after *Politico* told agency officials that the General Services Administration says federal rules require oversight staffers at federal agencies to approve first- or business-class trips "on a trip-by-trip basis ... unless the traveler has an up-to-date documented disability or special need."

EPA has said Pruitt flies first or business class because doing so is safer for him, a claim that some airline safety and security experts disputed.

GSA allows first-class travel for security reasons, but agencies must request a waiver for each trip.

More: *Politico*; *The Washington Post*

DOE Plans New Cybersecurity Office, Increased Funding

The Department of Energy is establishing a new Office of Cybersecurity, Energy Security and Emergency Response (CESER) and seeking expanded funding, Energy Secretary Rick Perry announced Feb. 14.

President Trump's fiscal year 2019 budget request proposes $96 million in funding for the office, which will focus on energy infrastructure security and support the department's national security responsibilities. The department said the new office "will enable more coordinated preparedness and response to natural and man-made threats."

CESER would take over responsibilities currently handled by the Cybersecurity for Energy Delivery System (CEDS) and the Infrastructure Security and Energy Restoration (ISER) programs, according to website Cyberscoop. CEDS would see its funding jump to $70 million from $45 million in 2018 under Trump's budget, while ISER's spending would grow to $18 million from $10 million, Cyberscoop reported. An additional $8 million would be spent on "program direction" — managing the workforce and contractors.

More: *Energy Department*; *Cyberscoop*

Senators Blast Trump's TVA Transmission Sale Proposal

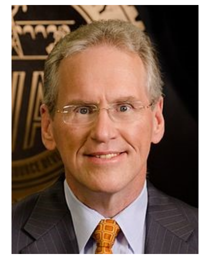
Two senators blasted a proposal in the infrastructure plan released Feb. 12 by the Trump administration to sell off the transmission assets of the Tennessee Valley Authority and three power marketing administrations.

"Oregonians raised hell last year when Trump tried to raise power bills for Pacific Northwesterners by selling off Bonneville Power, and yet his administration is back at it again," Sen. Ron Wyden (D-Ore.) said.

"This looney idea of selling TVA's transmission lines seems to keep popping up regardless of who is president. It has zero chance of becoming law," Sen. Lamar Alexander (R-Tenn.) said.

More: *The Washington Post*; *Portland Business Journal*; *WBIR*

TVA's Spending Brings Calls for CEO to Resign


Johnson

The Tennessee Valley Authority's purchases of corporate jets and a luxury helicopter once used by Dallas Cowboys owner Jerry Jones has prompted a review of the federal agency by its inspector general and calls for CEO Bill Johnson to resign.

TVA spokesman Jim Hopson said the private aircraft, which cost more than $35 million, are necessary for the agency because of a paucity of commercial flights in its 80,000-square-mile, seven-state service territory.

Stephen A. Smith, executive director of the Southern Alliance for Clean Energy (SACE), a watchdog group, said Johnson should resign. SACE was joined in criticizing TVA's spending under Johnson by the NAACP's Tennessee State Conference and Debbie Dooley, a Tea Party founder.

More: *Bloomberg*

Utah, Wyo. Intro Bills to Fund Challenges to Anti-Coal Laws

Lawmakers in Wyoming and Utah last week introduced bills to fund challenges to laws in California and Washington they think hurt coal sales.

A Utah lawmaker proposed allocating $2 million for fees to attorneys to challenge a California surcharge on Utah coal that was imposed as part of a cap-and-trade system to cut greenhouse gas emissions in the Golden State.

A Wyoming lawmaker introduced a bill that would let the legislature hire and pay for an outside attorney to sue Washington state for denying permits for a coal export terminal.

More: *Reuters*

STATE BRIEFS

ARIZONA

Bill Exempting Navajo Plant Coal from Sales Tax Clears Committee

The House Ways and Means Committee on Feb. 14 approved a bill that would exempt the coal used in the Navajo Generating Station in Page from sales tax by a 6-3 vote.

The bill is meant to help the Salt River Project, which operates the plant, find a buyer for it. SRP plans to close the plant at the end of 2019 if it can't.

Navajo Tribal Council Speaker LoRenzo Bates told a state Senate committee Feb. 14 that the tribe is talking with parties interested in purchasing the plant.

More: The Associated Press

CONNECTICUT

Bill Introduced to Restore Energy-Efficiency Money

Rep. Lonnie Reed (D), who chairs the General Assembly's Energy and Technology Committee, has introduced legislation to repeal the use of $145 million in energy efficiency funds to balance the state's budget.

The money comes from a charge on state utility customers' bills. Reed called its diversion "bait-and-switch-tactics."

Efficiency for All, an advocacy group created by energy efficiency contractors, said the diversion of the money could cost its industry as many as 6,800 jobs.

More: New Haven Register

MARYLAND

Delmarva Power Files to Pass Tax Savings on to Customers

Delmarva Power has filed a proposal with the Public Service Commission to pass the $13 million it will save because of the Tax Cut and Jobs Act on to its customers.

The company said that if its proposal is approved, the savings will fully offset a rate increase it was granted when the PSC approved a settlement between it, PSC staff and the Office of the People's Counsel on changes to its delivery rates.

More: WBOC

MASSACHUSETTS

FERC Approves Anbaric's Ocean Grid Tx Project

FERC on Feb. 12 authorized Anbaric Development Partners to sell transmission rights on its proposed Massachusetts Ocean Grid project, which would connect wind farms off the Massachusetts coast to ISO-NE's Southeast Massachusetts Load Zone (ER18-435).

The project would include two 1,000-MW offshore platforms with AC switching stations and two 1,000-MW HVDC transmission lines with 345-kV substations on the mainland.

Anbaric is developing the project to provide transmission capability to offshore wind developers competing in the state's request for proposals for offshore wind, which seeks up to 1,600 MW of offshore wind generation by 2027.

More: Anbaric Development Partners

NEVADA

NV Energy Asks to Reduce Rates by $837 Million Tax Savings

NV Energy on Feb. 14 asked the Public Utilities Commission to let it pass the $837 million it expects to save in taxes because of the Tax Cut and Jobs Act through to its customers.

If approved, the request by the subsidiary of Berkshire Hathaway Energy would reduce the monthly bill of single-family residential customers by 2.81 to 3.19%.

The company asked to let the bill reductions go into effect April 1.

More: Las Vegas Review-Journal

Contract Approved for Yucca Mountain Fight

The Board of Examiners voted last week to approve a two-year, $5.1 million contract with attorneys in D.C. to fight President Trump's proposal to resume work on turning Yucca Mountain into a repository for radioactive waste from the nation's nuclear power plants.

The Trump administration budget released Feb. 12 contains $120 million for the Department of Energy and $48 million for the Nuclear Regulatory Commission to restart the project.

Robert Halstead, who heads the Nuclear Projects Agency, said the contract is with the Austin, Texas, firm of Egan, Fitzpatrick, Malsch & Lawrence, which has represented the state on the issue in the past.

More: Nevada Appeal

NEW MEXICO

PNM Lambastes Environmental Group in Newspaper Ad

Public Service Company of New Mexico (PNM) placed a full-page ad in *The Santa Fe New Mexican* on Feb. 14 sarcastically thanking environmental group New Energy Economy for helping to defeat a bill it says could have enabled it to more rapidly replace coal power with renewable energy.

The bill would have allowed PNM to sell low-cost bonds to recover its investments in abandoned coal plants and use the proceeds to build renewable generation.

New Energy Economy called the bill a ratepayer "bailout" because PNM customers would have paid off the bonds through a surcharge on their bills.

More: Albuquerque Journal

OKLAHOMA

Bill Including Wind Tax is Defeated

A bill that would have imposed a $1/MWh tax on wind energy production and raised the initial gross production tax on oil and natural gas from 2% to 4% was defeated in the House of Representatives on Feb 12.

The bill, which was supported by a coalition of business and civic leaders called Step Up Oklahoma, contained a package of tax hikes totaling $581 million.

Sixty-three representatives voted for it and 35 voted against it, but tax increases in Oklahoma require a three-fourths majority to pass.

More: The Oklahoman

FERC Rules to Boost Storage Role in Markets

Continued from page 1

The order "will enhance competition in these markets and help ensure that they produce just and reasonable rates," staff told commissioners at FERC's open meeting.

The commission issued its Notice of Proposed Rulemaking on energy storage market participation in November 2016. It could be about two years until the new rules take full effect. (See FERC Rule Would Boost Energy Storage, DER.) FERC's directives will become official 90 days after their publication in the *Federal Register*. RTOs will then have nine months to file their tariff revisions, up from the six months proposed in the NOPR in response to requests for additional time, staff said. The grid operators would then have a year to implement the revisions.

The commissioners said the order demonstrated their commitment to ensuring they were not "picking winners and losers" in the markets. Commissioner Cheryl LaFleur noted that the markets "were largely designed around the resources that prevailed when they were launched" but have evolved to accommodate new technologies.

"I think the storage participation model required by today's order will facilitate storage being able to provide all the services it is technically capable of providing, for the benefit of consumers," she said.

The order is "the kind of positive regulatory action that removes barriers to competition, allowing emerging technologies to compete in the marketplace," Commissioner Neil Chatterjee said. "Put simply, it's good regulatory policy that people from all political backgrounds can support."

"In my view, today's final rule also strikes the appropriate balance between prescriptive requirements and high-level directives," Commissioner Robert Powelson said. FERC ordered RTOs/ISOs to take into account the unique physical and operational characteristics of storage, he said. "In doing so, we have given the RTOs and ISOs significant latitude to develop market rules that work best with existing market constructs and are respectful of regional differences," he said.

The Energy Storage Association applauded the order.

"With this morning's unequivocal action, the FERC signaled both a recognition of the value provided by storage today and, more importantly, a clear vision of the role electric storage can play, given a clear pathway to wholesale market participation," CEO Kelly Speakes-Backman said in a statement.

Powelson at ESA Policy Forum

FERC Commissioner Robert Powelson addresses the Energy Storage Association's Energy Storage Policy Forum. | © *RTO Insider*

In an appearance at ESA's Energy Storage Policy Forum at the National Press Club the day before FERC issued the rules, Powelson told attendees the order would demonstrate the commission's commitment to fair and open markets.

He also spoke about the larger trends in electricity, and how storage will have a bigger role to play under the new rules. Increased use of renewables has led to "market-based decarbonization," he said.

"Whether you're a fan of the Clean Power Plan or not, we are not building coal plants right now, and we are not building … 1,200-MW cathedral nuclear plants," Powelson said.

He pointed to the 2014 "polar vortex" and last month's cold snap. "No one [in D.C.] wants to talk about … the benefits of demand-side resources," Powelson said. "They want to talk about baseload, baseload, baseload."

Tech Conferences for DER

The commission had also proposed directing RTOs to give aggregated distributed energy resources the same treatment as storage, but on Thursday it said it needed more information before it could take action, ordering a technical conference to be held April 10-11 and opening new dockets for the issue (RM18-9, AD18-10).

Among the changes under FERC's proposal, a DER aggregator could register as a generation asset "if that is the participation model that best reflects its physical characteristics." The commission hopes to remove the commercial and transactional barriers to DER participation in wholesale markets.

Previewing the technical conference, LaFleur and Powelson said they were particularly interested in how DER operates and is compensated in both the wholesale and retail markets. "There needs to be a crisp understanding of who pays what to whom for what," LaFleur said.

"Distributed energy resources are becoming increasingly more integral to our resource mix, and we at the commission should make every effort to advance this issue without delay," Chatterjee said.

Speaking to reporters after the meeting, Chairman Kevin McIntyre acknowledged "the quasi-disappointment that I heard between the lines from some of my colleagues, which I share. It would have been great if we could have addressed both storage resources and distributed energy resources today. …

"But really, after looking at the state of the record on those two side-by-side issues, we determined that we needed to bolster our record on the distributed energy resource side of things. So I think our conference will be very useful."