RTO Insider

Your Eyes and Ears on the Organized Electric Markets

ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

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FERC Action Awaited Following PUCO Approval of PPAs

AEP to Sell Remaining Merchant Fleet?

By Ted Caddell and Rich Heidorn Jr.

Having won Ohio regulators' approval of their controversial power purchase agreements, American Electric Power and FirstEnergy now are hoping the PPAs will pass muster with FERC.

FirstEnergy's Davis-Besse Nuclear Power Station, one of the plants included in the company's power purchase agreement with Ohio. *Source: FirstEnergy*

The Public Utilities Commission of Ohio on Thursday unanimously approved modified versions of two PPAs, which the companies said are crucial to keeping some of their underperforming plants running in the state (14-1297-EL-SSO and 14-1693-EL-RDR).

On Monday, AEP and FirstEnergy formally notified FERC of the approvals.

Competing merchant generators have asked FERC to revoke the waivers it granted AEP and FirstEnergy regarding affiliate power sales to ensure a Section 205 review of the above-market deals (EL16-33, EL16-34). (See *PJM Joins EPSA's Call for FERC Review of Ohio PPAs*.)

In addition, 11 generating companies, including Calpine, Dynegy and NRG Energy,

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Stakeholders React to MISO Proposed Auction Design

By Amanda Durish Cook

A MISO proposal to hold a separate forward capacity procurement auction for deregulated areas is meeting with skepticism from some RTO members.

MISO stakeholders raised their concerns at a March 28 Competitive Retail Solution Task Team discussion focusing on the Forward Local Requirements Auction (FLRA) proposed last month. (See *MISO Proposes Adding Forward Auction for Retail Choice Zones*.) The task team plans to turn the proposal over to the Resource Adequacy Subcommittee (RASC) this month.

Zone 4 an 'Island'

Much attention was focused on Zone 4 in southern Illinois — MISO's only fully deregulated zone .

Aaron Patterson of The NorthBridge Group pointed out that Zone 4's local clearing requirement of about 5 GW during the 2016/17 planning year would leave more than half the zone's supply unused in a forward auction.

"What I'm wrestling with is — we have 10 to 11 GW of supply [in Zone 4] and sort of structurally only 5 GW" under the local clearing requirement, Patterson said. "The supply that doesn't clear is getting a price signal that it's not needed."

Jeff Bladen, MISO executive director of market design, responded that leftover supply would be applied to the planning reserve margin requirement.

"A lack of a forward signal is not lack of a need," Bladen said. "It is a lack of need for it to be a local resource."

Others said the FLRA would make Zone 4 even more of an "island."

Bladen said MISO would not introduce a new import constraint for the auction.

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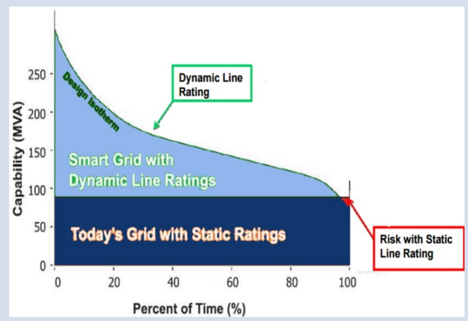
Transmission Summit

Of Ostriches, Deer, Lions and Cats

How Utility Conservatism is Hampering Transmission Innovation

By Rich Heidorn Jr.



Dynamic line rating (DLR) *Source: The Valley Group, June 2010 FERC technical conference*

WASHINGTON — Risk-averse engineers and outdated utility ratemaking structures are preventing quicker deployment of innovative technologies that could avoid transmission line rebuilds and save money, speakers told the Infocast Transmission Summit last week.

The discussion came in a session on how technologies such as dynamic line ratings, phasor measurement units and HVDC can increase the capacity of existing rights of

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GridLiance Closes Deal for Tri-County Co-Op's Tx Assets

By Tom Kleckner

Competitive transmission company GridLiance announced Monday it had closed its acquisition of about 410 miles of 69- and 115-kV transmission lines and related substation infrastructure from Tri-County Electric Cooperative (TCEC) in the Oklahoma Panhandle.

GridLiance CEO Ed Rahill called the transmission acquisition — GridLiance's first — "an important milestone" for its business model to partner with cooperatives and other public power agencies.

GridLiance, which was formed in 2014, acquired Tri-County's transmission assets and assumed full operational responsibility through its South Central MCN subsidiary, effective April 1. Under the transaction's terms, GridLiance will represent the co-op and its members' interest "in planning and development of new transmission projects within" SPP, the company said. The company announced the deal in September. (See *GridLiance Makes First Acquisitions*.)

Rahill said his company would assume operations and maintenance responsibility for Tri-County's assets, with the latter's "boots on the ground" employees providing some O&M services.

"Over the long term, we can provide TCEC with a clear path to invest in SPP transmission projects that will reduce network congestion, increase service reliability and lower service costs," Rahill said.

Tri-County CEO Jack Perkins said the move will allow the co-op to focus on its distribution system, with GridLiance upgrading the transmission assets. "Equally as important, we look forward to jointly investing with them in transmission projects that were previously inaccessible to us," he said in a statement.

Headquartered in Hooker, Okla., the cooperative serves about 23,000 meters in the Oklahoma Panhandle, southwestern Kansas, the northern border of the Texas Panhandle and parts of Colorado and New Mexico.

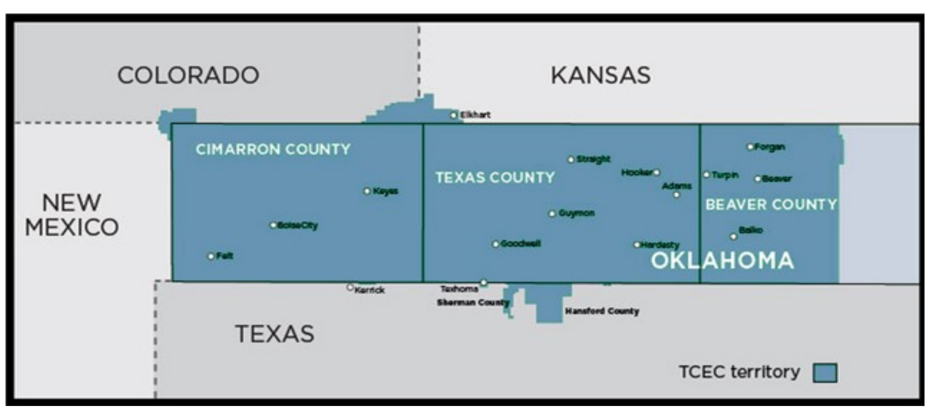
GridLiance says its planning and development models are focused on providing more reliable transmission to public power customers, "hedging rising costs for regionally planned projects." In addition to jointly planning, developing, owning and operating new transmission assets, GridLiance says it will work with entities such as Tri-County to identify "existing transmission infrastructure that can be more efficiently and cost-effectively upgraded and integrated into their RTO."

GridLiance also announced Monday additions to its operations and compliance teams with the appointments of several regional-industry veterans to leadership positions: Kevin Hopper (late of Associated Electric Cooperative Inc.), president of the SPP Region; Neal Chapman (LS Power), vice president of engineering; and Jim Useldinger (Kansas City Power & Light), vice president of operations.

All three will be based in GridLiance's Kansas City office and directly oversee the newly acquired TCEC transmission assets' engineering and operations functions. The company said they will work with COO Noman Williams and Trent Carlson, regulatory and compliance vice president, to "build out its platform into other regions."

GridLiance has also added several former SPP employees in recent months, including Brett Hooton, the RTO's senior interregional coordinator, and Jody Holland, its manager of steady-state planning.

GridLiance is backed by Blackstone Energy Partners, an affiliate of New York private equity giant Blackstone Group.



Tri-County Electric Cooperative *Source: TCEC*

Transmission Summit

How Utility Conservatism is Hampering Transmission Innovation

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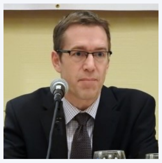
way.

Jack McCall, vice president of sales for Lindsey Manufacturing, likened DLRs and PMUs to technologies that can increase vehicle speeds on a curvy highway: PMUs are like Ferraris, which can take curves at high speeds; DLR, he said, is like straightening the road.

Gregg Rotenberg, president of Smart Wires, quoted former Southern Co. CEO David Ratcliffe, who said there are three types of transmission organizations: ostriches, who choose to ignore change; deer, who are frozen in place by change; and lions, who will seek to capitalize on the change and "are going to eat a bunch of ostrich and deer."

Ali Amirali, senior vice president of private equity fund Starwood Energy Group Global, offered a fourth type: cats, who are indifferent to change. He cited the Bonneville Power Administration, which he said views its mission as delivering hydropower to preferred customers and does not seek to maximize the capacity of the system because it's not part of the agency's "mandate."



"And they curtail wind all the time," interjected **Hudson Gilmer**, vice president of commercial markets for Genscape.

DLRs, which can measure conductor temperature, sag and line capacity, as well as detect icing and "galloping" — high-amplitude, low-frequency oscillation caused by wind — have been available for more than a decade, but early applications required scheduling an outage and deployment of bucket trucks and crews. "And once it was on a line, congestion is almost like whack-a-mole; it moves around on your network," Gilmer said. "And then it's very hard to get [operations and maintenance] dollars to move it to a new place."

"If you look back over the last 10 to 20 years, there have been so many studies done both in North America and elsewhere in the world that show that dynamic line rating truly does expose easily 10% to 25% additional capacity on any transmission line almost on a regular basis," added McCall. "It's a very low-hanging fruit."

Newer DLR technologies, such as those sold by Genscape and Lindsey, are easier to install but still face institutional inertia.

"Why do we not have real-time monitoring? … It's not the technology. It is the policies. It is the standards. It is the personnel and it's the decision making," Amirali said.

"The people who are running the grid — me included, [a] former operator — are about the most conservative people on Earth," he continued. "We are trained to be conservative. Because [if] an engineer takes a risk and he's successful, nobody really knows about it [because] the system operates the way it was supposed to. We take a risk and we fail: Chernobyl!"

The resistance to change also is a function of utilities' organizational structures and revenue models, speakers said.

"Risk doesn't stop us from doing deals," Rotenberg said. "The bigger challenge is those transmission organizations who choose to look at all the risk in front of them in terms of how fast the world is changing, how fast generation and load are changing and say, 'No I'm just going to keep building the lines and reconductoring every line possible because I think my ratepayers will keep paying it."

"What a utility gets rewarded on is deploying capital," agreed Amirali. "Why build one line when you can build two?"

Rotenberg said his company has proposed a $30 million deployment of its technology for a western utility as an alternative to a $175 million reconductoring.

"Every regulator who's heard about this project is saying, 'How can I make sure my utility does it?'

"Eight of 10 [utility] CEOs … do understand [the value of cheaper non-transmission alternatives]. Only six out of 10 vice presidents of transmission understand that," Rotenberg said. The transmission vice presidents' view, he said, is that congestion is "not my cost."

McCall said FERC should offer DLR compensation based on the difference in LMPs with and without constraints the devices relieve, similar to the way it designed the compensation scheme for demand response in Order 745.

Amirali said the commission also should reconsider its 2010 Western Grid Development ruling (EL10-19), which approved use of storage to defer a transmission upgrade but said such resources could not be used for any other purpose if they are receiving a rate of return. He said the ruling discouraged more widespread use of storage.

"You're buying a Cadillac for one day a year," he said. "It's a wasted use of an extraordinarily dynamic asset."

In a separate session, Philippe Bouchard, vice president of business development for Eos Energy Storage, praised Maine regulators for requiring utilities to evaluate untraditional transmission alternatives.

"It's not a requirement that they go purchase energy storage or demand response or anything else. It's just integrating that viewpoint into the methodology of looking at all available resources to meet their needs," he said. "And there's some really great opportunities, 15 or 20 miles of transmission lines that are stretching into the pockets of Maine that are ripe for [transmission and distribution] deferral."

Jeffrey Hein, senior manager of regional transmission policy for Xcel Energy, said planning regions across the country have included non-transmission alternatives in their procedures. "This may now begin to introduce some competition, to …. pit technology against technology, old, new, what's best to place where."

Rotenberg said "one or two big wins" are all that's required to change the mindset.

"Once we have one or two projects that everyone was certain were going to be a new line or rebuild and turn it into a non-wires alternative, everyone's eyes will open up," he said. "The hurdle [for building new lines or upgrades] is going to become much higher. The certainty … that that upgrade is required for a very long time is just going to keep going up and up."

Transmission Summit

Overheard at the Transmission Summit

WASHINGTON — More than 100 transmission developers, consultants, RTO officials and utility executives attended Infocast's 19th Annual Transmission Summit. Here's some of what we heard.

Competitive Transmission

Curt Bjurlin, an environmental services manager for Stantec, asked whether there are too many transmission developers chasing too few competitive opportunities under FERC Order 1000.

"I'm reminded of a story of a guy who comes to town and wants to play in a poker game and someone says 'Why do you want to play in that game? Don't you know it's rigged?' He says, 'Yeah, but it's the only game in town.'"

Bjurlin said he expects developers to employ more rigorous go/no-go decisions on bidding in the future.

Southern Co. is one utility that's not entering the game. "We've looked at that business continually and feel that there's enough players in that market and not a lot of projects to go after," said **Bruce Edelston**, vice president of energy policy. "So we decided to stick to our knitting in our own service area."

Lack of Interregional Transmission Projects

Edelston said the planning process isn't the reason for the lack of interregional transmission projects.

"It's whether there's somebody who is benefiting from that line who's willing to pay for it. … There are very few interregional lines that are going to be economic when you look at the alternatives available to the purchasing region — the region that would be receiving the renewable energy. They often have local alternatives or closer alternatives that don't require transmission fixes, and these long distance interregional lines can be very, very expensive — and as we're seeing with the Clean Line Energy Partners lines up in Illinois — very, very difficult to build."

"In our case, with the price of solar having come down so far, it turns out to be much more economic to build utility-scale solar within our service area than it is to build long-distance transmission to access wind in the Midwest. And I think that's true for a lot of East Coast load centers. You also have the opportunity these days to buy RECs — or renewable energy certificates — to meet any renewable portfolio standards that you have."

Jared E. Alholinna, regional transmission planning strategist for Great River Energy, recalled MISO's joint study with PJM, which identified up to 75 different "quick hit" transmission projects along their seam. (See *MISO, SPP Considering Second Joint Tx Study*.)

"Not one of them showed economic benefits. Many stakeholders thought this was a failure — you know, they're saying '0 for 75.'"

The real reasons for not finding a viable project, he said, included the success of MISO's multi-value projects in reducing congestion and low natural gas prices that make it cheap to redispatch around congestion.

"There have been projects on the border that are on the cusp of meeting criteria, but when you have two different RTOs, you have two different needs and you have two different approval processes. And trying to get all those stars aligned we're finding is very, very difficult."

Xcel Seeking Larger Dispatch Areas in the West

Gerald R. Deaver, manager of regional transmission policy for Xcel Energy, said although his company's operators have developed expertise in making their systems more flexible, the increasing penetration of renewables is creating operational challenges.

"Xcel has been pushing the development of regional markets in the West because we think geographic diversity is the best way to deal with some of this imbalance between regions or areas with renewables. And it seems to be getting more traction in the West."

"We're trying to develop along the Front Range [in central Colorado and southeastern Wyoming], a common dispatch area with a number of entities, both [FERC] jurisdictional and non-jurisdictional, to try and widen that footprint. … I doubt you could go Western Interconnection-wide with, for example, an RTO, but we're really pushing for bigger geographic areas for dispatch. That's going to require probably some additional transmission interconnections."

Xcel has reduced its carbon emissions by 20% since it began adding renewables in 2005, and its Colorado Public Service unit now gets 60% of its energy from wind during some hours of the day, Deaver said. "We've been able to line up long-term purchases of wind at steadily decreasing prices."

Distributed Energy Resources

Eric Ackerman, director of alternative regulation for the Edison Electric Institute, said the planning for distributed energy resources will require granular data regarding both customer energy use and system status that few utilities currently capture, even though some 65 million interval meters have been deployed.

"But even if we have the data, the next issue is … do we want to give the data to the market? Because in California and in New York the preference is to have market-based third-party suppliers deliver the distributed energy. So the market is endlessly hungry for this data. They'd like it in real time. They'd like it constantly updated. And utilities — my members — are pushing back. They think their distribution franchise requires them to plan the system. And if they give too much of the data to the market, guess what? The market's going to run away with that and they will lose control of their plan."

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Transmission Summit

Overheard at the Transmission Summit

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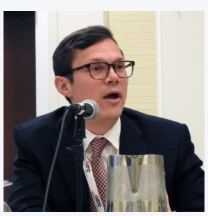
Stuart Nachmias, vice president of energy policy and regulatory affairs for Consolidated Edison, said, however, there is a win-win opportunity for utilities and new entrants. "The [cost of] solar technology is coming down. But if you talk to the solar companies, their biggest cost is customer acquisition. And to the extent that utilities together with solar companies or battery providers ultimately can help reduce that acquisition cost and share in those savings there's tremendous value."

Nachmias also gave an update on his company's plan to use distributed generation and demand-side management to address overloads in Brooklyn and Queens and delay the need for a $1 billion substation upgrade for a decade. (See NYPSC OKs Con Ed's Demand Management Program to Relieve NYC Overloads.) "Stitching together the solution [is] really complex — much more than we thought," he said. "And getting customer engagement is very difficult."

Market for Grid-Scale Storage



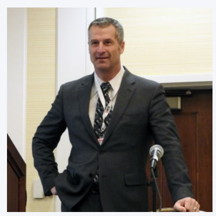
Philippe Bouchard, vice president of business development for Eos Energy Storage, said that frequency regulation has been good for energy storage — responsible for about 80% of the 200 MW deployed last year.

"However the challenge with that market and application is … it's a pretty shallow market. If you compare the amount of money that flows through FR in PJM relative to the energy market or the capacity market, it's tiny. And the more assets that get built to provide that service are essentially cannibalizing the revenue streams that they can monetize.

"To me the real drivers of the market are going to be projects more like [Southern California Edison's request for four hours of locational capacity] — large-scale longer duration projects that are providing services under long-term contracts with creditworthy off-takers. These are projects that are easily financed, that are providing a reliability service to the grid and which offer flexibility too."

Alex Ma, senior manager of regulatory affairs for Invenergy, said grid operators will need to change their interconnection process in order to realize the potential storage has for supplementing variable energy resources.

"From an interconnection standpoint, it seems very difficult to get past the fact that you have two different technologies at the same [point of interconnection]," he said, recommending changes to "fast-track some of the resources — not necessarily based on size as they are today with small and large generation — but on technology."



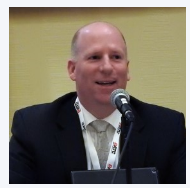
Brad Jones, CEO of NYISO, said storage is central to New York's effort to create a more resilient grid following Superstorm Sandy. "The best technology for meeting resiliency at the distributed grid is having storage located there — having storage located at all the major substations to serve that load if they get disconnected."

But, citing a Brattle Group study, he said only 40% of storage's value is in resiliency. "The remainder of the value of storage comes from operating in the market. Recognizing that they can store energy at nighttime when it may be zero or negatively priced and can release the energy in the day when it's positive. I'd like to see a way if we can figure out a way to capture those other benefits as well — perhaps allow the utility companies to auction off the energy value that exists in the wholesale market and then let others take that to market."

John Jung, CEO of Greensmith Energy Management Systems, said the number of companies seeking a share of the energy storage industry will decline in the future. "There's going to be a lot of consolidation in this space. It's very natural. I've seen it in a lot of other spaces where there's a lot of [venture capital] money. There was some $270 million in VC money that poured into this industry."

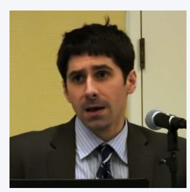
Clean Power Plan

Gil Rodgers, senior managing director for natural gas markets at Energyzt, said he thinks the Clean Power Plan will likely survive legal challenges. "So it would be a mistake, it would really be foolish, not to consider the fact that this is something that's coming down the road."

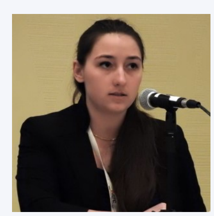


Missouri Public Service Commissioner **Scott Rupp** said RTOs "can use [the CPP] to start making cases to build more transmission. Most of the people that make up them that have a lot of weight are the transmission companies."

"I think it's uncon-testable" that the Clean Power Plan will be "a big driver for transmission," agreed Larry **Eisenstat** of law firm Crowell & Moring.



Michael Ferguson, director at Standard & Poor's, said states should not wait to respond to the rule. "We all know that when it comes to building a generator profile, building the transmission lines tends to be the long pole in the tent. … So if you're a state that's relying really heavily on new transmission build, it's something that you probably don't want to put off for too long."



Kerry Worthington, a program officer for the National Association of Regulatory Utility Commissioners, also had advice. "My message to you today is to not depend on your assumptions and leave your options open," she said. "It's very difficult to predict with accuracy what the Clean Power Plan will look like after the stay."

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Transmission Summit

Overheard at the Transmission Summit

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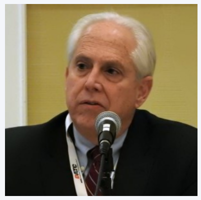
David Treichler, director of modeling and analytics at Oncor, predicted it would not be long before overnight load in Texas was served entirely by wind energy. “Things are going in this direction. CPP is not going to be the major driver for a clean Texas. Economics will be. … Government is not always the provocateur of our pain.”

Despite the CPP and competition from wind and cheap gas, some coal generation will be around for decades, said **Todd Williams**, a partner with ScottMadden. He noted that the average lifespan of a coal plant is 55 years and the newest one was built a year ago. “We’re going to have coal in the portfolio through at least 2070, if not beyond. … Coal’s not going away completely. Reminds me of the Monty Python skit ‘Not Dead Yet.’”

Improving Gas Infrastructure



“I would like to see going forward, in the next five years, coordinated planning discussions between the gas industry and the RTOs,” said **John Lawhorn**, MISO’s senior director of policy and economic studies.

“We have found that if you have a good fuel assurance program, like New England ISO has for several years, you don’t have electric reliability problems,” said **Henry Chao**, NYISO vice president of system resource planning.

“Ensuring that gas gets to the generators is definitely not currently in the job description of the ISOs or RTOs, as it’s currently written,” said **Tanya Bodell**, executive director at Energyzt. “Ensuring … reliability is; creating market-based incentives … to maintain that reliability most certainly is available.”

— Rich Heidorn Jr. and Michael Brooks

ERCOT NEWS

ERCOT Stakeholders Agree on Lost Opportunity Costs Rule

By Tom Kleckner

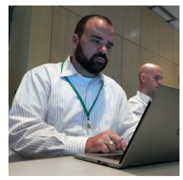
AUSTIN, Texas — ERCOT's Technical Advisory Committee last week agreed on a method for paying lost opportunity costs to generators ordered to ramp down for grid reliability, a solution that will now go to the ISO's Board of Directors.

Stakeholders discussed three options brought forth by ERCOT staff to address Nodal Protocol Revision Request 649 (Addressing Issues Surrounding High Dispatch Limit (HDL) Overrides), which was remanded back to TAC during the board's February meeting. (See *LOC Rule Sent Back to ERCOT's Stakeholder Process*.)

Staff's preferred option was the first of three it presented: rewriting the NPRR's language to replace compensation for opportunity costs with "justified" losses suffered by qualified scheduling entities (QSEs) holding existing contracts. The QSEs would have to provide an attestation of loss, calculations and supporting documentation to recover a claim.

A second option proposed software changes to override the resource node's LMP, which would have created difficulties at the 98 nodes with at least two generator connections. The third, and priciest option, at $200,000 to $300,000 plus ongoing support, would pre-position manual constraints associated with each resource node in the system model.

As the discussion wore on, it became apparent stakeholders were coalescing on the first of ERCOT's options.



Whittle

"This seems to be a quickly diminishing issue," said Shell Energy's Greg Thurnher, representing independent power marketers. "It looks like Option 1 is the remedy."

"We think Option 1 is the way to go for now," said Megawatt Analytics' Brandon Whittle, speaking for Odessa-Ector Power Partners and Koch Services. "It puts the onus on the people who might get hurt. No generator wants to be paid back for their losses because of HDL overrides. We'd rather adjust the LMPs."

The proposal passed by a 23-5 vote, with two abstentions. The NPRR will go before ERCOT's board April 19. Staff will revise the revision request's impact analysis and better define energy bilateral contracts.

Odessa-Ector, a subsidiary of Koch Ag & Energy Solutions, initiated discussion of the issue when it claimed its combined cycle plant had lost $300,000 because of three days of dispatch overrides in November 2012. ERCOT submitted the NPRR to satisfy a settlement agreement with Odessa-Ector after the company filed a complaint with the Public Utility Commission of Texas (docket #41790).

Luminant's Amanda Frazier expressed a preference for an earlier version of the NPRR, which failed to secure sufficient votes. But she said that in subsequent discussions, "ERCOT has eliminated a number of concerns we originally had.

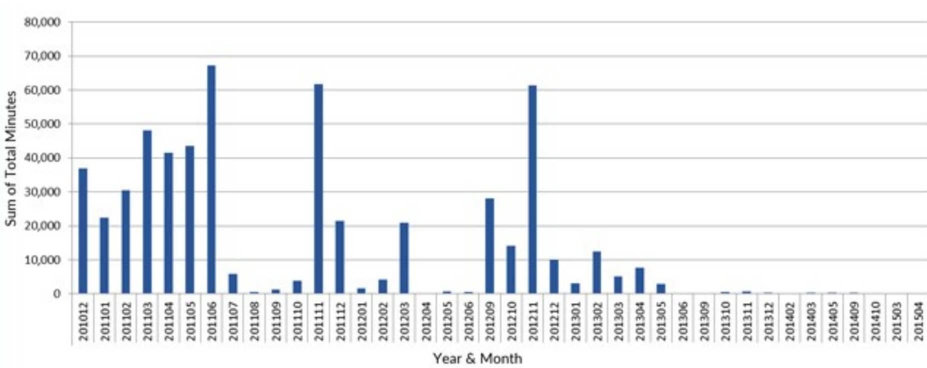
"The damages are limited to those attested to by the resources, and compensating the actual damages rather than the opportunity costs is a good compromise," she said.

Resmi Surendran, ERCOT senior manager of market analytics and design, highlighted staff's efforts to reduce HDL overrides, which peaked at more than 348,000 minutes in 2011. The numbers have steadily dropped since then, with only 57 minutes of overrides recorded last year.

Surendran attributed the improved results to increased operator training, their ability to enter manual constraints, the availability of new generic transmission constraints and topology improvements.

Whittle sought reassurance from ERCOT that the NPRR's cost can be reduced from its current staff estimate of $100,000 to $150,000.

"We try to implement [any changes] at the minimum cost we can," said Kenan Ögelman, ERCOT's vice president of commercial operations. "We'll definitely go back and see if we can't reduce the cost. I just can't give you a number, right now."



Total time in minutes HDL override in place (2010-2015) *Source: ERCOT*

ERCOT Approaches 50% Wind Penetration Mark

ERCOT continues to creep closer to the 50% mark for wind penetration, reaching 48.28% of load on March 23. The Texas grid operator said last week it generated 13,154 MW of wind energy at 1:10 a.m., when the overall load was 27,245 MW.

The ISO's previous high for wind penetration was 45.14%, set Feb. 18. Its wind peak remains 14,023 MW, also set Feb. 18.

ERCOT has 15,764 MW of installed wind capacity. Wind energy accounted for 18.4% of its system generation in 2015.

— Tom Kleckner

ERCOT NEWS

Technical Advisory Committee Briefs

TAC to Schedule Data-Exchange Workshop

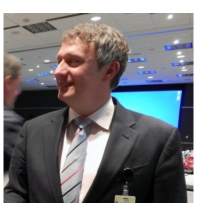
AUSTIN, Texas — Technical Advisory Committee Chair Randa Stephenson and Kenan Ögelman, ERCOT's vice president of commercial operations, last week suggested a workshop to discuss how ERCOT and its market participants exchange data and handle changes to data reports.

Denton Municipal Electric's Lance Cunningham raised the issue by noting that staff told the Market Data Working Group it was issuing a 30-day notice — as required by ERCOT's protocols — to change an existing wind-projection data report. Cunningham said that change would require an estimated 30 person-hours to make changes to the muni's systems.

Several stakeholders sided with Cunningham, pointing out modest software changes can cost tens of thousands of dollars.

"Multiply that cost by the number of [market participants] that have to do it, and you're in the millions pretty quickly," The Wind Coalition's Walter Reid said. "We need to be aware of what we're doing."

"[ERCOT's] ability to unilaterally change reports has been a concern of mine," said Calpine's Randy Jones, representing independent generators. "I realize there are passages in the protocols to provide data to ERCOT upon [its] request, but the time may be ripe for a discussion that we start putting criteria around that … and mitigate the huge impact it has."


Ögelman

Ögelman, while noting the change will actually take place June 30, did agree with Cunningham that such changes create inconveniences.

"It can be burdensome to adjust to [changes]," he said. "Long term, do we need to start thinking about another way we exchange data, rather than people scraping it off a report? Right now, this is the only way certain people can get this data. I think it's very important to consider whole systemwide impact of changes."

"You need a report you can input and utilize," said Sharyland Utilities' B.J. Flowers. "Maybe you utilize the workshop as business-requirement gathering, and hand it over to the market data group to work on the details."

Stephenson told stakeholders she is working with ERCOT to schedule the workshop.

NPRRs Approved, NOGRRs Tabled

TAC members approved five Nodal Protocol Revision Requests.

- NPRR 741: Clarifications to estimated aggregate liability (EAL) and total potential exposure (TPE) credit exposure calculations.
- NPRR 744: Reliability unit commitment trigger for the reliability deployment price adder and alignment with RUC settlement.
- NPRR 745: Change emergency response system availability from an hourly to 15-minute interval evaluation, plus other minor changes.
- NPRR 746: Adjustments due to negative load.
- NPRR 748: Revisions associated with NERC reliability standard COM-002-4 and other clarifications associated with dispatch instructions.

Luminant's Amanda Frazier, chair of the Protocol Revisions Subcommittee, said NPRR 744 exceeded ERCOT's $100,000 impact-analysis threshold, but she noted staff filed comments that determined the ISO would have saved more than $9 million "over the last several months" if the revisions had been in place.

"We at PRS felt that was adequate justification for approving this process," Frazier said.

The committee also tabled a Nodal Operating Guide Revision Request and an appeal of a second NOGRR:

- NOGRR 151: Alignment with NPRR 748, revisions associated with COM-002-4 and other clarifications associated with dispatch instructions.
- NOGRR 149 would exempt distribution service providers without transmission or generation facilities from having to procure designated transmission operator services from a third-party provider if their annual peak is less than 25 MW. Jones expressed sympathy for the small municipalities most affected. "On the other hand," he said, "it doesn't seem to be fair to the market. Small entities are not carrying their obligations."

Staff Share Reports, Updates

Staff shared the Emergency Response Service (ERS) report that is filed annually with the Public Utility Commission of Texas. ERCOT procures ERS three times during the year for four-month terms. Participants can provide the service for one or more of four time periods, which are designed to allow flexibility for customers during traditional business hours.

ERS expenditures are capped at $50 million. Staff said expenditures for last year were $48.8 million.

TAC also approved the Retail Market Subcommittee's goals for 2016 and discussed staff updates on ERCOT's debt strategy and changes to ERCOT's antitrust admonition and guidelines.

ERCOT Treasurer Leslie Wiley shared feedback from her recent report to the Finance and Audit Committee. She said the ISO uses congestion revenue rights (CRRs) auction receipts — with a limit of $100 million — along with debt and revenue to fund its liquidity. Wiley said the committee encouraged her to use CRRs when available to fund long-term projects, but there are questions about how to pay for significant unbudgeted initiatives.

The ISO currently has an Aa3 credit rating. "We want to maintain that," Wiley said.

ERCOT's legal department is revising the antitrust guidelines to be a position statement. Nathan Bigbee, ERCOT's senior corporate counsel, said there shouldn't be any cause for concern, "as long as actions ERCOT takes fall within [its] authority under federal or state laws."

— Tom Kleckner

ISO-NE News

ISO-NE Again Defends Capacity Auctions

By William Opalka

ISO-NE CEO Gordon van Welie last week again defended the RTO's capacity auction to congressmen who say market practices have led to inflated electricity rates for New England ratepayers.

In an eight-page, single-spaced letter sent Monday, van Welie reminded the New England congressional delegation of his testimony three years ago that highlighted the dramatic shift in the region's market.

"Since then, 4,200 MW of resources have either announced plans to retire or have actually retired. Importantly, since 2013, the region's Forward Capacity Market (FCM) has procured over 4,700 MW of new capacity resources — demonstrating that the FCM is procuring new, economically competitive resources to meet the region's energy needs," he wrote. (See *Prices Down 26% in ISO-NE Capacity Auction*.)

Van Welie's letter was a response to a March 14 letter sent to FERC and the RTO by the delegation members after results of the 10th Forward Capacity Auction were filed.

ISO-NE Forward Capacity Auction results *Source: ISO-NE*

"While these clearing prices were the result of a 'competitive auction' according to ISO-NE, the results are roughly equal to FCA 8, an auction that triggered administrative pricing rules due to lack of competition. They are also triple the capacity payments derived from the auctions prior to FCA 8," the delegation wrote.

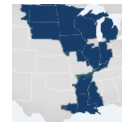
The congressmen acknowledged that prices declined more than 25% from FCA 9, but they noted that the previous year was a record $4 billion.

Ten senators and representatives joined in the letter, which was written by Massachusetts Democrats Rep. Joseph P. Kennedy III and Sen. Edward Markey. The members have repeatedly complained to FERC, without success, about alleged market manipulation. (See *Congressional Meeting Fails to Sway LaFleur on Capacity Results*.)

Van Welie said that market participants respond to price signals.

"We share your goal of ensuring that prices in the capacity market are just and reasonable. The FCM must and does signal the true value of capacity in New England. Artificial prices (whether too high or too low) do not benefit regional electric reliability or New England residents," he wrote.

MISO NEWS



MISO Proposes 3 New MTEP 17 Futures

By Amanda Durish Cook

MISO last week proposed the adoption of three new future scenarios intended to inform the development of the 2017 Transmission Expansion Plan (MTEP 17).

Jenell McKay, a MISO senior analyst, told participants at a March 30 workshop that stakeholders are seeking a "range of modeling futures and some form of carbon reduction modeling" to assist in the planning cycle.

The three retooled "futures" include:

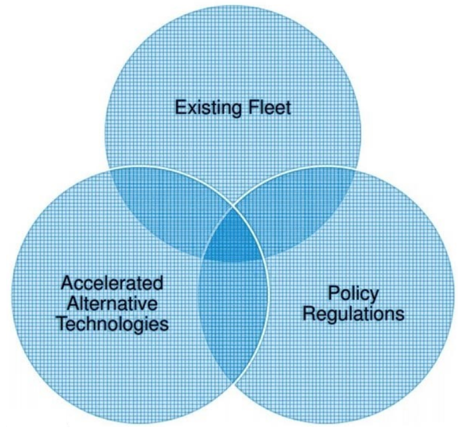
- An "existing fleet" narrative in which MISO's generation fleet is largely unchanged because of low demand and no carbon regulations are modeled. Already-planned coal retirements are factored into the scenario, and remaining coal units retire only after reaching their 65-year age limits. MISO also assumes renewable tax credits will expire in 2022, existing nuclear units will stay online and low natural gas prices and a stagnant economy curb renewable growth. As a result, gross aggregate demand grows at just 0.3 to 0.4%, and the energy growth rate is similarly low at 0.4 to 0.5%.
- A "policy regulation" future based on the final Clean Power Plan rule, with a 25% reduction of carbon emissions across MISO, which drives 16 GW of coal retirements and increased reliance on mid-range-priced natural gas. MISO also assumes that nuclear units remain online and non-nuclear, non-coal generators retire according to 55-year age limits. Aggregate demand grows at the current 0.8 to 0.9% rate, while energy growth hovers around 0.7 to 0.9%.
- An "accelerated alternative technologies" future in which a "robust" economy propels expanded demand, leading to a 35% carbon reduction and steering MISO to 24 GW worth of coal retirements. This future assumes high natural gas prices, retirement of non-nuclear, non-coal generators at 55-year age limits, license renewals for nuclear units and continuation of renewable tax credits beyond 2022. Aggregate demand and energy consumption growth rates both surpass 1% under the scenario.

To address stakeholder concerns about price volatility, all future scenarios assume a 30% variance between high and low natural gas prices during the study period. McKay said assumptions about storage technologies were not included in any of the narratives but could be inserted during an "R&D phase" over the next few months.

In response to several questions about why MISO is not modeling a business-as-usual case for MTEP 17, McKay responded that industry uncertainties about carbon regulation, coal retirements and renewable penetration made a definite BAU scenario elusive. "We didn't feel comfortable calling anything business-as-usual," she said. "For instance, if the CPP is upheld [following court challenges], the policy regulation future will be the business-as-usual case."

Matt Ellis, MISO manager of policy studies, said stakeholders can still weigh in on the futures. "Do they pass a smell test? Are they reflecting what's already happening on your factory floors?" he asked.

MISO hopes to continue discussion about the futures at an April 20 Planning Advisory Committee before putting them to a vote at the May PAC meeting.



Proposed MTEP17 futures *Source: MISO*

OMS Asked to Back Modeling Allowance Auction

Meanwhile, the Organization of MISO States could urge MISO to model a carbon emissions allowance auction after being approached by the Coalition of MISO Transmission Customers about the issue last week.

Coalition representative Robert Weishaar told a March 31 OMS meeting that he raised the issue with MISO staff, who he said were "reluctant" to model the net cost of CPP CO_2 allowances that are auctioned rather than allocated.

Weishaar said he was not advocating an auction over an allocation but wanted to see both hypotheticals in MISO's CPP modeling. "We've taken a particularly critical interest in MISO CPP modeling to date," he said.

Calling the omission a "gap in the MISO modeling approach," Weishaar asked for OMS' support in endorsing a future letter on the matter.

Libby Jacobs of the Iowa Utilities Board said she would support such a letter, but other OMS members expressed indifference.

Texas Public Utility Commissioner Ken Anderson said an auction may affect generator dispatches and the fuel mix, but those points were moot. "Because we're in the 'just say no' camp to the CPP, we're not particularly interested in MISO modeling," Anderson said.

MISO NEWS

FERC Extends Comment Period on Great Northern Agreements

By Amanda Durish Cook

FERC last week granted Missouri River Energy Services (MRES) an extension to comment on a series of "zonal agreements" submitted by ALLETE and Great River Energy to resolve revenue-sharing and cost recovery disputes (ER16-1107, *et al.*).

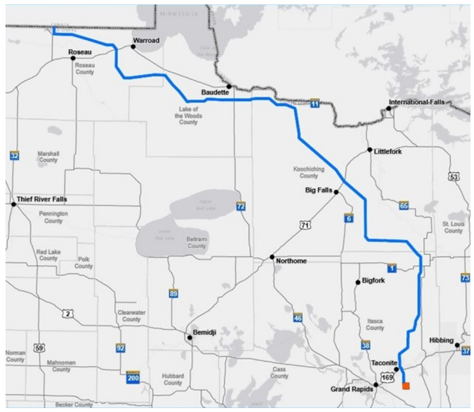
The commission extended the commenting deadline to April 5, a week short of MRES' request but four days longer than what ALLETE and GRE were willing to concede.

The agreements would resolve the two companies' disputes over revenue-sharing and cost recovery for transmission projects in MISO's Minnesota Power (MP) pricing zone — including the proposed Great Northern Transmission Line linking the region with hydro resources in Manitoba.

ALLETE and GRE filed a joint answer urging the commission to disregard the protest by MRES, which contends the agreements were negotiated "outside of commission processes" and could be inconsistent with MISO's Tariff.

"These complex, interrelated agreements proposed by the applicants as a black box settlement that implicitly cannot be 'pried apart,' present a challenge of analysis because of their complexity and lack of transparency," MRES wrote in a March 24 filing.

"All of MRES' claims are either procedurally improper or unfounded and should not delay the commission's approval of the zonal agreements," the two companies countered.



Great Northern Transmission Line approved route
Source: Minnesota Power

MRES' concerns have less to do with the revenue-sharing portion of agreements than with their possible implications for transmission cost allocation within the MP pricing zone. Chief among of those concerns is whether ambiguous language in the settlement opens the door for ALLETE to eventually roll costs related to the 500-kV Great Northern line into its revenue requirement, a move MRES said should be prohibited under MISO's Tariff because the project is participant-funded.

ALLETE and GRE counter that MRES is pursuing its concerns under the wrong proceeding — that the revenue-sharing methodology under the zonal agreements represents a separate issue from Great Northern's cost allocation. The companies say MRES should raise allocation concerns under the Tariff's Attachment O protocol, which deals with project cost recovery.

The two companies also defended the settlement process and its outcome, saying their agreements "worked within the context" of MISO's Transmission Owner Agreement, which spells out how transmission revenue should be distributed in pricing zones with multiple transmission owners.

"MRES' protest, at best, reflects a misunderstanding of the process used to negotiate the zonal agreements as well as such agreements' fundamental purpose," the companies said.

ALLETE and Great River insist that if they "had not resolved their differences, they would have been forced to litigate complex and fact-intensive issues" regarding MISO pricing zone boundaries, asset classification for cost allocation purposes and revenue sharing for select facilities and load within the MP pricing zone.

"This litigation likely would have taken years and resources away from all parties (including MISO and commission staff), who all may prefer to focus on other areas," the companies said.

FERC OKs MISO Use of Eastern Standard Time in Day-Ahead Market

MISO's day-ahead market schedules may continue to use Eastern Standard Time instead of Eastern Prevailing Time even as the RTO alters scheduling deadlines to comply with updated gas nomination cycles, FERC said (ER15-2256).

The commission last week ruled that MISO could persist in having its day-ahead market become effective at 12 a.m. EST, despite using EPT for other scheduling deadlines.

In a Jan. 19 compliance filing related to gas-electric coordination, MISO sought permission to continue using EST because "accommodating transitions to and from daylight saving time would require significant implementation costs to MISO and its market participants, while providing little, if any, quantifiable benefits." MISO explained that moving to EPT would "divert resources and funding from higher priority initiatives."

FERC agreed that MISO "sufficiently explained the discrepancy between its using EST for establishing when its day-ahead market schedules become effective and its using EPT for all other scheduling deadlines."

The commission also approved MISO's request to begin posting day-ahead market results by 1:30 p.m. EPT (12:30 p.m. CT), saying the new deadline provides natural gas-fired generators sufficient time to procure fuel and secure pipeline transportation ahead of the 1 p.m. CT timely nomination cycle. FERC additionally accepted a related MISO provision to move the day-ahead market trading and interchange scheduling deadlines to 10:30 a.m. EPT (9:30 a.m. CT) in order to meet the new posting time. (See *FERC Orders MISO to Shift Electric Schedule*.)

The schedule changes become effective Nov. 5 for the Nov. 6 operating day.

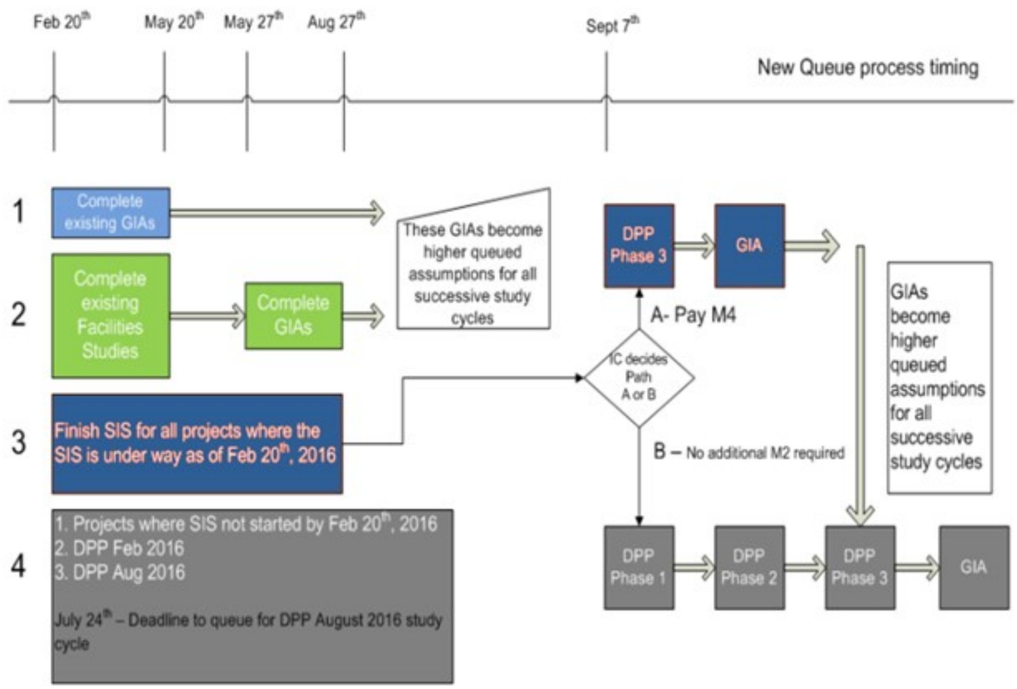
— Amanda Durish Cook

MISO NEWS

FERC Orders MISO to Charge Uniform Interconnection Fees

Opens Separate Proceeding to Revise MISO Tariff

By Amanda Durish Cook



Transition plan for new MISO queue rules *Source: MISO*

MISO must charge equal fees to all generators entering its interconnection queue regardless of whether they are internal, external, new or existing resources, FERC ruled last week (EL15-99).

The commission also directed MISO to revise its Tariff to spell out procedures related to external resources entering the queue, a process currently described only in the RTO's Business Practice Manuals. FERC agreed with a group of MISO generators who contended that the absence of an explicit Tariff provision created a lack of transparency around the nature of RTO service agreements with external resources.

"The commission requires that matters that significantly affect rates and services, are readily susceptible of specification and are not so generally understood be in the Tariff rather than Business Practice Manuals," the order stated.

FERC considered the issue significant enough to open a separate Section 206 proceeding (EL16-12) to review MISO's Tariff and require revisions outlining specific procedures and milestone payments for all interconnection customers.

The ruling stems from a complaint by a group of internal MISO generators who contested the RTO's practice of exempting external generating resources from paying a significant fee levied on any new internal resources seeking to enter the final stage of the interconnection process.

At the outset of the definitive planning phase (DPP), any new MISO interconnection customers within the footprint must make an M2 milestone payment to fund system impact and interconnection facilities studies, as well as a later network upgrade facilities study, before preparing a construction schedule and cost analysis. Existing internal generators are exempted from the payments. MISO also waives the fee for both new and existing generators outside its footprint under the assumption that those resources have already established interconnection agreements within their own balancing areas.

The complainants contended that the differing payment requirements represent a competitive disadvantage for them because external generators face a "significantly lower entry fee than generation internal to MISO." The generators further argued that the lack of monetary collateral tied to the DPP phase could lead external resources to submit speculative project requests or nonchalantly withdraw projects, forcing MISO to revise its study assumptions and thereby delay other projects in the queue. They asked FERC to consider two options: Either force MISO to require all new interconnection customers to pay the milestone payments or eliminate the payments altogether in the interest of fairness.

In its answer to the complaint, MISO said the request to treat existing external generation identically to new internal generation was unjust and unreasonable. The RTO pointed to the milestone payment exemption for existing generation, also noting that the payments are refundable upon finalizing a generator interconnection agreement. The RTO said it would resolve the payment dispute by charging "some form" of initial payment to external customers wanting to enter the queue.

In its ruling, FERC went a step beyond the complainants' original request by requiring all interconnection customers — including existing internal generators — to post milestone payments.

"All interconnection customers, whether they are new or existing, or internal or external, are seeking interconnection service and will be entering the DPP," the commission said. "The Tariff provisions should ensure that all interconnection customers, internal and external, and new and existing, are treated comparably."

FERC gave MISO 60 days to update its Tariff with the changes related to the interconnection process. The changes must include a *pro forma* service agreement and initial payment details for external resources. A final order on the matter is expected by Nov. 30.

NYISO NEWS

Management Committee Briefs

Winter Gas Record Set

New York's natural gas demand set a single-day record in February, although the winter was much milder than the average over the past 30 years.

The winter operations review presented at the NYISO Management Committee meeting on Wednesday showed that only three relatively brief cold snaps occurred over the winter, with the worst one in mid-February. Cold snaps in December and January, when daylight hours are shorter, have greater potential to stress the electric system, said Wes Yeomans, NYISO's vice president of operations.

On Feb. 13, during the coldest three-day period of the winter, the ISO set a 6.6 Bcf single-day record for natural gas demand, exceeding the previous mark of 6.4 Bcf set in February 2015. Yeomans said 100% of the natural gas system's capacity was reached that day, for both heating and electricity generation.

The record was as much a function of the low cost of natural gas as power demand, Yeomans said. "Gas prices remained below oil prices for the day," he said.

NYISO relies heavily on dual-fuel capable generation, so when natural gas supply becomes constrained — or when it becomes uneconomic relative to the cost of oil-fired generation — fuel-switching becomes more widespread. That did not occur during this stretch.

The peak load in mid-February was 22,951 MW. No demand response resources were called upon this winter.

"Our winter peak was below the 50/50 forecast by quite a bit," Yeomans said. The peak of 23,317 MW on Jan. 19 was the lowest winter peak since at least 2004. The forecasted peak was 24,515 MW.

Yeomans said the fuel-monitoring platform the ISO created to improve reliability also appeared to be "working well."

ICAP Demand Curve Reset

The committee voted to set the capacity market demand curve every four years with an annual reset, an increase from the current three-year cycle. The demand curve was introduced more than a decade ago.

"The change is recognizing calls from stakeholders," said Paul Hibbard, vice president of the Analysis Group, the consultant hired by NYISO.

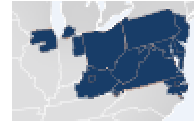
The changes more accurately reflect the New York wholesale market as generation assets enter and leave, Hibbbard said. The annual reset would consider the gross cost of new entry and forecast energy and ancillary services revenues, as well as adjusting historical revenues to reflect market conditions.

Another factor in extending the cycle is the 18 to 20 months needed for setting the demand curve.

The change needs to be ratified by the NYISO Board of Directors. Further refinements would be performed over the next several months, in advance of a filing with FERC by Nov. 30. NYISO anticipates an operational date of May 1, 2017.

— William Opalka

PJM NEWS



Grid 2.0 Asks DC PSC to Reconsider Merger Approval; OPC Mulls Action

By Suzanne Herel

One party to the Exelon-Pepco Holdings Inc. merger case has asked the D.C. Public Service Commission to reconsider its approval, and the People's Counsel said she's considering doing the same.

Grid 2.0, which advocates for distributed generation, and did not sign on to any proposed settlement in the case, said in a March 25 filing that the commission failed to give adequate notice of public hearings and did not provide support for its finding that the settlement it crafted itself was in the public interest.

"The commission … failed to make any *independent* finding that the revised settlement agreement is in the public interest," it said, calling the PSC's conclusion "arbitrary and capricious."

The nine settling parties, who approved an initial agreement that was later amended by the commission, have until April 22 to file an application for reconsideration with the PSC. Four other groups that intervened but did not sign on to the settlement also have the opportunity to appeal the decision.

The joint applicants responded to the filing, saying "every part of Grid 2.0's argument is wrong."

"The commission approved the merger after two years of the most exhaustive consideration that the commission has ever given to any issue, and it did so based on one of the most extensive records the commission has ever compiled," they said.

D.C. People's Counsel Sandra Mattavous-Frye said last week on the Kojo Nnamdi radio show that she is reviewing the ruling with an eye toward issues that might warrant her office taking action.


Mattavous-Frye

"I do have some major concerns about the process throughout the case. You didn't really know what to expect or how the commission came to its determination," she said. "It's not over until it's over. But I do admit that the lift is going to be heavier at this junction."

Exelon and Pepco closed the $6.8 billion transaction just hours after the PSC approved the deal on March 23. (See *Exelon Closes Pepco Merger Following OK from PSC*.)

Mattavous-Frye cited "uncertainty created by the commission's plan," specifically how it plans to use $32.8 million of the $72.8 million customer investment fund that commissioners "redirected … for themselves without any clear explanation of how those funds will be used."

If the commission stands by its decision, parties may turn to the D.C. Court of Appeals.

The acquisition, approved on a 2-1 vote with Chairwoman Betty Ann Kane in opposition, creates the country's largest utility by customer count.

In an interview last week with the *Washington Business Journal*, Exelon CEO Chris Crane and new Pepco head David Velazquez said they would work to prove themselves to merger opponents and will be active in district affairs.

FERC Staff: Reject Coaltrain 'Rhetoric'

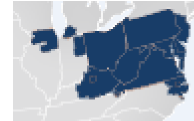
FERC staff told the commission Friday that a Pennsylvania-based power trading company's response failed to dent their case that the company made riskless up-to-congestion transactions to collect line-loss payments. Staff asked the commission to uphold its findings and order the company to pay $42 million in penalties and unjust profits.

"Despite the rhetoric deployed throughout their lengthy submissions, the respondents do not credibly rebut the factual and legal conclusions in the staff report," staff said in its response to Coaltrain Energy's March 4 filing (IN16-4). The company's answers to FERC's Order to Show Cause contended it didn't manipulate the market, that its trading strategy wasn't deceptive and that it didn't engage in wash trades or try to affect market prices.

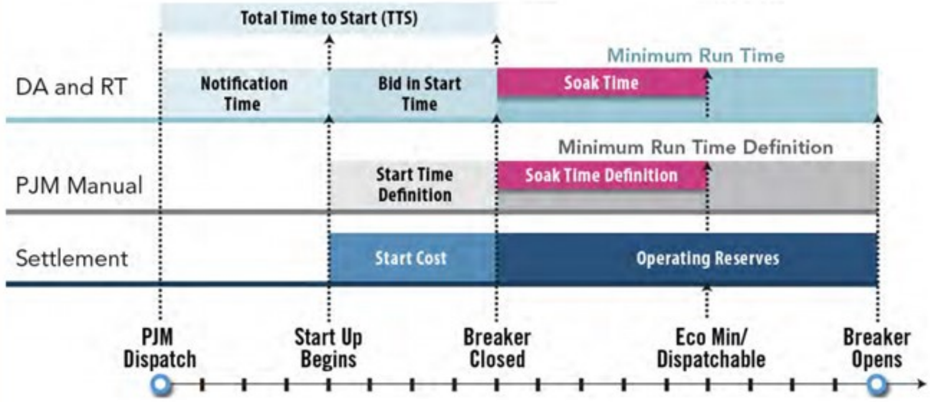
As part of its response, staff included screenshots of one Coaltrain trader's computer showing that he entered 137,800 MWh of "Over-Collected Losses" trades just three minutes after starting work on one day — evidence, staff said, that the trades were not based on "any meaningful research" but were intended to profit on the losses alone. Staff said Coaltrain also made misleading statements to PJM's Independent Market Monitor in July and August 2010 in which it "falsely promised to stop making trades aimed at [collecting line-loss payments] after the IMM warned that trading to do so was illegitimate."

More: *Traders Deny FERC Charges; Seek Independent Review*

PJM NEWS



MRC/MC Briefs



Proposed operating parameter definitions *Source: PJM*

MRC Fetes Kormos in Absentia

Kormos

WILMINGTON, Del. — Mike Kormos, the departing chair of the Markets and Reliability Committee, couldn't attend his last meeting because of a scheduling conflict, said CEO Andy Ott, who lauded his colleague for his nearly three decades of work at PJM.

"As he and I grew through the ranks of PJM, I saw him as a partner, and I think you all saw him as a person you could talk to on any subject and collaborate with," he said. "I'm going to miss him. PJM is going to miss him. He has been with us for 28 years, and there's just no replacing that kind of experience."

Ott has said the position will not be filled.

Kormos, executive vice president and chief operations officer, announced his resignation last month. His last day with PJM is April 15. (See *PJM COO Kormos Leaving; Post Won't be Filled*.) He has not indicated his future plans.

CFO Suzanne Daugherty, the new chair, presided over her first committee meeting. Members passed around Kormos' place card, on which they penned parting sentiments.

Members OK Operating Parameters but Urge Refinements

The MRC unanimously approved changes to Manual 11: Energy and Ancillary Services Market Operations; Manual 15: Cost Development Guidelines; and Manual 28: Operating Agreement Accounting. The revisions define operating parameters. (See "Operating Parameter Definitions Approved," *PJM Market Implementation Committee Briefs*.)

The changes to Manual 15, regarding start-up and no-load costs, also were endorsed unanimously by the Members Committee.

An alternate proposal put forward by Bob O'Connell of Main Line Electricity Market Consultants was not taken up for a vote because the initial motion passed.

Combined cycle units traditionally have been disadvantaged by these definitions, he said. Minimum run time begins when the first gas turbine is synchronized, he said, leaving open the possibility that PJM could release a unit before the steam turbine is synchronized. O'Connell's definitions included a calculation that would let PJM know when the steam turbine had been synched.

While the parameters would not invoke a nonperformance charge under the new Capacity Performance construct, they could affect make-whole payments, PJM's Adam Keech said.

While O'Connell's definitions were not considered, a number of members and the Independent Market Monitor agreed that the issue he raised should be addressed.

PJM's Adrien Ford, who chairs the Market Implementation Committee, pointed out that the problem statement leading to the operating parameter definitions had been amended in his committee, allowing for ongoing conversations about them.

Keech said that even if the alternate definitions were approved, PJM programmers wouldn't be able to implement them by June 1, when the new delivery year begins under CP rules.

"We have a bunch of significant compliance obligations coming down the pike that we are trying to work through as soon as we can," he said. "While I understand the value of these changes, they don't fall into compliance changes. I'm not certain what date we could hit with these."

If the way the parameters are used is changed, especially for combined cycle units, it would require changes to the software and how PJM clears the day-ahead markets, he said.

Ed Tatum of American Municipal Power encouraged PJM to continue studying the issue.

"The stakes are huge," he said. "AMP is very concerned about how these parameters are going to be implemented. They could have draconian impacts on a supplier. It is important from our standpoint to get it right — and if we can't get it right, to think about transitioning things so we're not unduly burdening or penalizing people. This is a grave concern."

MRC, MC Endorse Interim Ramp Rate for Performance Assessment Hours

MRC members approved a temporary performance assessment hour ramp rate with a 77% sector-weighted vote. The interim solution also was approved by the MC, over 11 objections.

The vote calls for revisions to Tariff and Manual 18: PJM Capacity Market. (See "PAH Ramp Rate for CP Approved," *PJM Operating Committee Briefs*.)

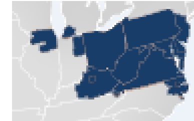
Market Monitor Joe Bowring voiced his opposition. "This significantly weakens the incentives of Capacity Performance," he said. "We regard this as a direct contravention of FERC's no-excuses policy. It's not a good idea."

Assistant General Counsel Jen Tribulski said that PJM's filing with FERC will explicitly note that the ramp rate is an interim measure to "get us through the coming months."

"We fully intend to continue the discussion,"

Continued on page 16

PJM NEWS



MRC/MC Briefs

Continued from page 15

which will include the issue of using original equipment manufacturing specifications, she said.

MC Votes to Flex Meeting Start Time Following MRC

Following a lively debate, the Members Committee voted to flex the start time of its meetings going forward. The change will ensure that lunch is preserved, which members said is valuable for networking.

The issue had been raised at the last meeting by John Horstmann of Dayton Power & Light, who asked if there was a way to streamline the work of the MRC and MC, which are held on the same day.

On Thursday, he suggested allowing the MRC — which usually has a meatier agenda than the MC — to run as long as necessary in order not to truncate debate and have the MC start 15 minutes to a half hour after it ends. If necessary, members will break for lunch during the MRC meeting.

Ten members objected.

Scheduling Changes Approved

The MRC unanimously approved revisions to transmission and energy scheduling practices to reflect PJM's adjustment to its day-ahead energy market timeline. The changes include adding a five-minute "shotgun window" for the spot-in product. (See "Day-ahead Submission Deadline Moved up," *PJM Market Implementation Committee Briefs*.)

MRC, MC Approve Updated Definitions, Clarifications to Governing Documents

The MRC approved updated definitions and clarifications to PJM's governing documents. They involve the terms PJM board, market participant, credit breach, PJM region, regional entity, affiliate, PJM markets, economic minimum and transmission customer.

The MC also endorsed changes to governing documents as well as additional clarifications to previously endorsed revisions.

In addition, that committee approved Tariff and Operating Agreement revisions regarding the definition of the term counterparty. In an Aug. 27 vote, the word was removed from a batch of proposed definitions and returned to the Governing Documents Enhancements and Clarifications Subcommittee for further review at member request. The definition was aligned to use more precise language in the OA that specifies when PJMSettlement will and will not be a counterparty to a transaction or agreement.

Dave Anders, director of stakeholder affairs, and CFO Suzanne Daughterty *Source: PJM Inside Lines*

Changes to Confidentiality Rule Allow Release of Certain Information

With two objections and one abstention, the MRC approved changes to Manual 33: Administrative Services for PJM Interconnection Agreement that allow PJM to release market data under six circumstances. (See "Market Data Confidentiality Rule Change Gets First Reading," *Market Implementation Committee Briefs*.)

They address individual generation outages, the availability of demand response, cleared and offered capacity resources, information regarding uplift payments, results of the three pivotal supplier test and member data that has been made public by that member or a regulatory agency.

MRC Approves Manual Changes

The following manual changes were endorsed at Thursday's meeting. Three of the votes were unanimous. There was one abstention on the changes to Manual 11 regarding Capacity Performance.

- Manual 1: Control Center and Data Exchange Requirements. Adds new section for planning, coordination and notification of system changes and events; includes new content with updated procedures. New Attachment C is the new Inter-Control Center Communication Protocol (ICCP) failover test plans diagram. Revisions remove references to the PJM ICCP network interface control document and PJM ICCP communications workbook.

PJM's Ryan Nice said that some companies had been found to be taking outages of a few minutes on their emergency management systems and not alerting PJM. "The implications of that are quite serious," he said.

- Manual 6: Financial Transmission Rights. Housekeeping changes resulting from annual review. Clarifications better describe existing rules and processes.
- Manual 11: Energy and Ancillary Services. Changes accommodate the implementation of Capacity Performance regarding unit-specific parameters. For non-Capacity Performance resources, the status quo remains until 2018. From that delivery year on, unit-specific parameters for base capacity resources will apply during hot weather alerts, emergency actions during hot weather operations and when being offer-capped to maintain system reliability. For CP resources, beginning in delivery year 2016, unit-specific parameters will apply during hot weather alerts, cold weather alerts, emergency actions and when being offer-capped to maintain system reliability.
- Manual 11: Energy and Ancillary Services Market Operations. Revisions reflect day-ahead market timeline changes. Among them: the deadline for submitting day-ahead bids will be 10:30 a.m. The day-ahead clearing window will be reduced to three hours. The deadline for posting day-ahead results will be 1:30 p.m. or as soon as practicable. Results will be posted upon approval but not before noon.

— Suzanne Herel

Advertisement

SPP News

Briefs

MMU Report Highlights SPP's Increasing Reliance on Wind Energy

The SPP Market Monitoring Unit's State of the Market report for the winter months once again highlighted wind generation's growing importance within the RTO's footprint.

According to the report, which covered December 2015 through February 2016, wind generation accounted for 17.7% of SPP's energy, a 43% increase from last winter. Wind generation accounted for 12.4% of energy production last winter and 10.2% during the winter of 2014.

As if to punctuate the point, SPP set a new wind peak during the evening hours of March 28, shortly after the market report was released. The RTO's new wind peak of 10,809 MW at 9:22 p.m. CT broke the previous record of 10,783 MW, set March 21. Wind penetration reached 40.34% March 28, short of the 41.1% high set March 7.

Wind generation peaked in February, producing nearly 21% of SPP's energy, according to the Monitor's report. SPP has 12,397 MW of installed and available wind capacity in its footprint, with another 33,819 MW in various stages of development.

The increase in wind power came at the expense of coal generation, which saw the percentage of energy it produced fall to 46.3% for the month, down from 57% in February 2015.

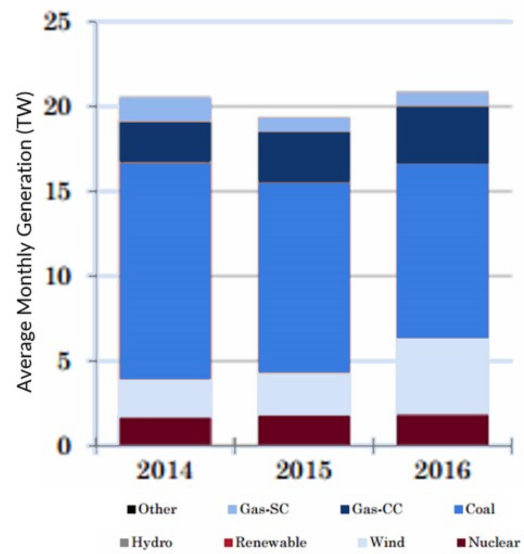
The report said the increase in wind generation "comes [with] an increase in congestion." Most congestion in the SPP footprint can be found in the "wind alley" of the Texas Panhandle, western Oklahoma and western Kansas.

The Monitor measures congestion by a constraint's shadow price, "which reflects the intensity of congestion on the path represented by the flowgate." It said the shadow price "indicates the marginal value of an additional megawatt of relief on a constraint in reducing the total production costs."

Shadow prices reached almost $60/MWh on one flowgate and topped $40/MWh on at least two other flowgates.

The Monitor report also said gas costs continued to drop during the winter, with an average Panhandle Hub cost of $1.98/MMBtu, more than 30% lower than 2015 ($2.90/MMBtu) and nearly two-thirds lower than 2014 ($5.68/MMBtu).

The average real-time balancing market's winter 2016 LMP was $17.82/MWh, down from $25.20/MWh in 2015. The day-ahead market's average LMP was $18.33/MWh, down from $25.73/MWh last winter.



Generation by fuel type, real time *Source: SPP 2016 Winter State of the Market report*

SPP, AECI Begin Biennial Joint-Study Process

SPP and Associated Electric Cooperative Inc. (AECI) began their biennial joint-study process with a call for stakeholder feedback and input on a proposed scope last week.

The SPP-AECI Interregional Stakeholder Advisory Committee (IPSAC) has identified several voltage and congestion issues in Missouri and Oklahoma, but the committee said April 1 it is giving stakeholders two to three weeks to comment on the scope. A separate meeting will be scheduled for the study scope's formal endorsement.

The IPSAC will evaluate the SPP and AECI transmission systems and determine whether "mutually beneficial" joint projects exist. A joint planning committee comprising a representative from each staff will determine cost allocations on a case-by-case basis, with responsibility "assigned equitably" based on the constraint being resolved — and subject to approval of each region.

The two entities have been performing joint studies every other year since 2010, as outlined in their joint operating agreement. The 2014 study identified 463 potential needs along the SPP-AECI seam but resulted in no joint solutions.

Stakeholders asked staff whether this study might solve long-standing constraints in the Lake of the Ozarks region in central Missouri.

"We studied some alternatives in the last joint-study process related to a 345[-kV line] across this lakes area, but we did not see a lot of economic value or immediate reliability concerns a line across that area would solve," said David Kelley, SPP's director of interregional relations. "But constraints obviously move around, so we're always willing to look at an alternative."

James Vermillion, a senior planning engineer for AECI, said the association's latest 10-year Long Range Transmission Plan has identified almost $40 million in improvements to maintain grid reliability. Still, that is down from the 2009-19 plan, which identified more than $221 million in projects.

AECI, based in Springfield, Mo., is owned by and provides wholesale power to six regional generation and transmission cooperatives.

SPP.org Wins Best Energy Website Award

SPP's recently redesigned website has been honored as the Best Energy Website in the 2016 Internet Advertising Competition (IAC) Awards.

SPP.org was redesigned by Little Rock interactive agency Aristotle, which called the new site "a case study in responsive web design that combines great aesthetics and interactive technical features without sacrificing speed."

The IAC Awards highlight the "best online advertising" in 96 industries and nine online formats, including video, newsletters, email and social media.

— Tom Kleckner

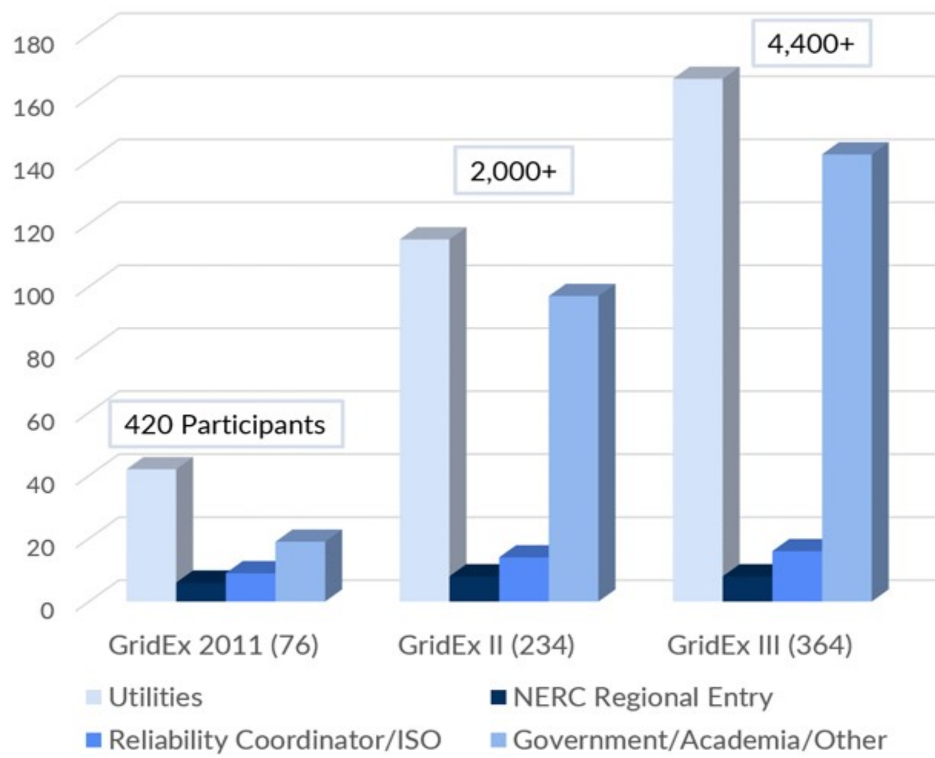
GridEx III Shows Vulnerability of Power Grid to Cyberattack

By Ted Caddell

GridEx III, a drill to test the emergency response capabilities of the North American high-voltage power grid, highlighted several vulnerabilities in the face of a simulated cyberattack. The lesson: Responding to a wide-scale computer malware attack is completely different from overcoming a monster storm.

"Electricity system recovery and restoration would be delayed or may not begin until the nature of the cyber risks are understood and mitigation strategies are available," said NERC's final report on the November drill.

GridEx III drew 4,400 participants from grid operators, federal agencies and local, state and federal law enforcement. The two-day scenario hit the grid with cyber and physical attacks resulting in blackouts in several cities. Organizers sent waves of simulated malware to grid operators by email. Throughout the beginning stages of the drill, operators were also notified about simulated attacks on physical plants such as transmission lines and substations.



GridEx participating organizations *Source: NERC*

"We wanted to challenge the coordinators to be on that ragged edge … [to see what they need to do to] protect the reliability of the system," Bill Lawrence, NERC associate director of stakeholder engagement, said during a press conference Thursday.

The scenario employed email delivery of simulated malware — a tactic used by hackers who attacked three utilities in Ukraine in December. (See *How a 'Phantom Mouse' and Weaponized Excel Files Brought Down Ukraine's Grid*.)

The after-action reports showed that secure sharing of communication between parties and reporting methods remains a problem.

"Industry needs to coordinate with local law enforcement to identify and assess the physical risks to electricity facilities and workers," the report said. "Unlike how industry responds to major storms through mutual assistance, industry's capability to analyze malware is limited and would require expertise likely available from software suppliers, control system vendors or government resources."

Another observation was that the information-gathering tools may be capturing too much. The NERC-run information portal captured reports in real time, but participants said they and the system quickly became overwhelmed.

NERC, the report said, "should continue to enhance the [information] portal to support real-time, searchable, urgent communication and collaboration."

Another major observation gleaned from the simulated cyber and physical attack was that recovery would be prolonged and expensive. "Utilities will need unprecedented levels of financial resources in order to restore their facilities and eventually resume normal operations," the report said.

The massive expense of a widespread restoration effort raised a question: Where is that money going to come from?

"There are certain regulations and laws out there that could be useful for grid restoration," Lawrence said. "For example, the Stafford Disaster Relief and Emergency Assistance Act is designed to deliver relief and funding to individuals that are impacted by a disaster."

But the law doesn't provide relief for private corporations, such as investor-owned utilities. "Obviously if the utility isn't generating power, they can't pay their employees, and that would be a severe impact," Lawrence said.

GridEx III featured the first use of social media for communications purposes. The report also recommended lengthening the planning time for the next exercise.

Company Briefs

Central Hudson CEO Promoted, Replacement Named


Laurito

Central Hudson Gas & Electric appointed Michael L. Mosher as CEO, effective April 1. He succeeds James P. Laurito, CEO since 2009, and who has been promoted to executive vice president of parent company Fortis. Laurito will remain on the Central Hudson board.

Central Hudson board Chair Margarita K. Dilley said Mosher has the experience, knowledge and vision to propel the utility to new heights of accomplishment in a rapidly changing industry.

"Mike's substantial and diverse background in operations and regulatory affairs has prepared him to assume the leadership of Central Hudson at a critical time in its evolution," Dilley said. "We are confident that he will continue the momentum that our company has achieved during Jim's outstanding tenure."

More: *Central Hudson Gas & Electric*

Wind Farm Developer Facing Bankruptcy

SunEdison, saddled with nearly $10 billion in long-term debt, is at risk of filing for bankruptcy protection, one of its affiliates said.

In a Securities and Exchange Commission filing last Tuesday, TerraForm Global said "liquidity difficulties" mean that "there is a substantial risk that SunEdison will soon seek bankruptcy protection." The company is also reportedly being investigated by SEC for possibly overstating to investors how much cash it had on hand in November.

More: *Portland Press Herald*

Peabody, Arch Announce 465 Layoffs at 2 Wyo. Coal Mines

The two largest coal mines in the U.S., both in Wyoming, announced massive layoffs last week. Peabody Energy cut 235 people, or 15% of the workforce, March 31 at North Antelope Rochelle. Arch Coal said the same day it was cutting 15%, or 230 people, at its Black Thunder Mine.

Until now, Wyoming's coal industry has largely avoided the massive cutbacks seen in Appalachian coal operations. The two mines, which produce about 100 million tons of coal a year, are generally regarded as among the most cost-effective mines in the country.

More: *Billings Gazette*

PacifiCorp to Close Coal Unit At Wyoming's Kemmerer Plant

PacifiCorp has abandoned plans to convert a coal unit at its Naughton Plant in southwestern Wyoming to natural gas, saying it will now retire the unit at the end of 2017. The company said the move is a result of declining electricity demand and reflects the costs of installing environmental upgrades to meet federal haze requirements.

PacifiCorp's initial plan had been to shutter Unit 3 for five months, starting at the end of 2017, and convert it to natural gas. The estimated cost of the conversion was $160 million. Natural gas had been a cheaper option for complying with regional haze requirements than upgrading the unit's coal burning equipment under the Oregon-based utility's initial calculations.

More: *Casper Star-Tribune*

AECC, Ouachita Dedicate 100-Acre Ark. Solar Farm

Aerojet Rocketdyne, Arkansas Electric Cooperative Corp. and Ouachita Electric Cooperative Corp. formally commissioned a 100-acre solar project in southern Arkansas last week. The 12-MW array located in an industrial park will supply power to Aerojet's nearby facility.

The facility was completed in late 2015 and is capable of generating enough electricity to power the equivalent of 2,400 single-family homes. Excess solar energy will be sold in the wholesale power market.

More: *Magnolia Reporter*

DTE Proposes 10-Acre Solar Farm in Vacant Detroit Parcel

DTE Energy is proposing the development of a 10-acre solar array on a former playground in Detroit, which the utility said "could be one of the largest urban solar arrays in the U.S."

The project, in Detroit's Grandale neighborhood on the former O'Shea Park, would produce 2 MW, enough for 330 residential customers.

More: *MLive*

Consumers Energy: Cheapest Natural Gas in Almost 2 Decades

Consumers Energy has reported that its natural gas commodity price has fallen to its lowest level in 18 years.

Consumers' natural gas commodity price for April is $2.54 per 1,000 cubic feet, which represents the most inexpensive rate since March 1998. Consumers estimates that the average residential customer paid $250 less this winter on natural gas bills.

"The price for natural gas that we'll put into effect in April continues a decade of falling costs," said Tim Sparks, the utility's vice president of energy supply operations.

More: *Consumers Energy*

Solar Capacity Awarded to 4 Companies in Tenn. Project

The Tennessee Valley Authority, together with the Tennessee Valley Public Power Association, has awarded 16.7 MW of solar capacity to four local power companies for projects expected to generate enough electricity to supply more than 1,300 homes.

The projects were chosen from 11 proposals that are part of the Distributed Solar Solutions pilot project. TVA has more than 400 MW of solar power under contract.

More: *Solar Industry Magazine*

Duke Energy Asks to Upgrade Ohio River Hydro Station

Duke Energy is seeking permission to modernize its Markland Hydro Station on the Ohio River near Florence, Ind. The company wants to replace three hydroelectric turbines, generators and related equipment.

If the proposal is approved by the Indiana Utility Regulatory Commission, work on the hydro station could begin this summer and

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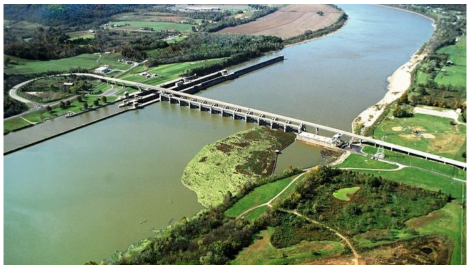

last until mid-2020.

"The generating units at Markland Hydro have served our customers well with clean, renewable energy since 1967," said Melody Birmingham-Byrd, president of Duke Energy Indiana. "As we move toward increasingly cleaner energy, these modernized generation units will harness more of the renewable resources of the Ohio River for many years to come."

More: *Duke Energy*

SandRidge Energy Flirting With Bankruptcy Decision

SandRidge Energy, an Oklahoma City oil and gas exploration company, has informed the Securities and Exchange Commission that it has talked with advisers about the possibility of filing for bankruptcy. Plunging natural gas prices and depressed energy demand have left a number of energy companies with onerous debt burdens.

The company laid off nearly 200 employees, including three executives, earlier this month. It has outstanding loans of nearly $600 million.

More: *KOCO*

Berkshire Power Pleads Guilty To Emissions Violations

Berkshire Power, the operator of a Western Massachusetts power plant, has agreed to plead guilty and pay $8.5 million for tampering with air pollution monitoring equipment and reporting false data about emissions levels.

Federal prosecutors say that employees at Berkshire Power in Agawam, Mass., manipulated the emissions monitoring system between January 2009 and March 2011 to conceal excess emissions. The actions were violations of the federal Clean Air Act.

The plant's managers also violated the Federal Power Act for lying to ISO-NE about the plant's availability to produce power, the first-ever criminal charges under that statute, according to the Justice Department.

More: *The Boston Globe*

Federal Briefs

Technology Companies Support Clean Power Plan

Technology giants Apple, Amazon, Google and Microsoft filed a joint friend of the court brief in support of EPA's Clean Power Plan, hoping to strengthen the agency's position against legal challengers.

The companies said that they believe that the CPP "reflects reasonable and attainable assumptions about the increasing availability of renewable generation in the nation's power sector."

The case is expected to be heard in the D.C. Circuit Court of Appeals in June.

More: *9to5Mac*

Inspection Finds Broken Bolts At Entergy's Indian Point Unit 2

More than a quarter of the bolts securing plates directing water around uranium fuel rods at Entergy's Indian Point 2 nuclear reactor were found to be either broken, deformed or missing, according to a report released on March 29.

The March 7 inspection by Entergy found that 227 of the 832 bolts were either

damaged or missing, a failure rate of 27.2%. The company and the Nuclear Regulatory Commission may order a similar inspection of Indian Point 3 to see if there is a similar bolt issue.

The missing fasteners are a concern because similar bolt damage was identified as the cause of a partial meltdown of the Fermi reactor in 1966.

More: *The Huffington Post*

FERC Delays Approval Of 2 Pa. Pipelines

FERC has delayed the timetable to review two proposed Marcellus Shale natural gas pipelines, pushing the potential approval dates into early 2017.

The Atlantic Sunrise project in Pennsylvania, a Williams Partners project, was seeking authorization from FERC by the end of April. The FERC schedule expects the review to be completed in January 2017. That pipeline is planned to run south from Susquehanna County to link up with an existing Transco pipeline in Lancaster County.

The PennEast Pipeline, a $1.2 billion 114-mile line that is to run from Northeastern Pennsylvania into New Jersey, sought approval from FERC by August of this year. But the FERC schedule shows the review won't be completed until March 2017. PennEast is a UGI project.

More: *Central Penn Business Journal*

Bird Conservancy Group Targets 3 Wind Farms

The American Bird Conservancy says that three proposed wind projects near migration routes or important avian rookeries should not be built because they represent threats to endangered birds.

The conservancy said the turbines at two of the proposed wind farms, in North Dakota and in Kansas, are near migratory paths of the federally protected whooping crane. A proposed wind farm in northwest Missouri

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could threaten some of the migrating birds that use the Squaw Creek National Wildlife Refuge, including snow geese, bald eagles and trumpeter and tundra swans.

"There's plenty of data to suggest that plenty of birds are being struck by the blades on these turbines," a conservancy spokesman said. "Hundreds of thousands at a minimum." The conservancy said wind farms in such areas should probably be prohibited.

More: *Midwest Energy News*

41 Companies Volunteer To Cut Methane Emissions

EPA and 41 energy companies announced a partnership to voluntarily reduce methane emissions from natural gas operations at the Global Methane Forum in D.C. last week.

Called the Natural Gas STAR Methane Challenge Program, the partnership is aimed at curbing methane emissions at wellheads and at various points along transportation systems.

The partners include Southern California Gas, whose gas storage well in California leaked thousands of tons of methane earlier this year. Other companies include Exelon, Duke Energy, TransCanada and Xcel Energy.

More: *The Associated Press*

Federal Weather Researchers See Record Ice Retreat in Arctic

NASA and the National Snow and Ice Data Center say the maximum ice buildup in the Arctic is coming in low this year. Ice growth for February was 1.16 million kilometers below average. And March's reading, at 14.52 million square kilometers, was the lowest maximum extent on record.

This is the second straight winter that showed below-average maximum ice extents.

"Records attract attention, but the critical thing is, what's the trend," a member of the National Academy of Sciences' Polar Research Board. "This is just part of the overall trend of unraveling in the Arctic."

More: *The Washington Post*

DOE Wants to Move 7 Tons Of Plutonium Cross Country

The Department of Energy is considering shipping nearly 7 tons of weapons-grade plutonium from the department's Savannah River Site in South Carolina to the Waste Isolation Pilot Plant in Las Cruces, N.M.

The plan is going forward despite the fact that the New Mexico plant has been closed since February 2014 due to a fire and unrelated radiation release there. The plutonium was to be de-weaponized at the South Carolina site, but now the department plans to dilute it to a level where it can be shipped. The New Mexico facility is more than 2,000 feet below ground.

"The importance of keeping nuclear materials out of the hands of terrorists is clearer today than ever and is essential to protecting our nation and allies," said the National Nuclear Security Administration.

More: *Albuquerque Journal*

State Briefs

REGIONAL

Model to Simulate Distributed Energy's Impact

Avangrid is working with the MIT Energy Initiative to create a model to simulate the integration of distributed energy resources into the grid.

The model could support New York's Reforming the Energy Vision plan by simulating how distributed resources, such as solar arrays and battery storage systems, might impact the power system. This model seeks to identify the scale at which distributed resources become beneficial to the grid while taking into account potential impacts on electricity prices, grid reliability and the environment.

The collaboration is part of MITEI's broader Utility of the Future Study. Avangrid is the newly formed affiliate of the Iberdrola Group that operates New York State Electric and Gas, Rochester Gas and Electric, Central Maine Power and United Illuminating.

More: *MIT Energy Initiative*

Near Record-Low Power Prices Set in New England

The average price of wholesale electricity, pushed lower by depressed natural gas prices, last year dropped to the second-lowest level in 12 years in New England, according to preliminary figures from ISO-NE.

The lowest and second-lowest average monthly power prices were in June at $19.61/MWh and December at $21.35/MWh. The second-lowest annual average price of wholesale electric energy was set last year at $41/MWh, with the lowest annual average price at $36.09/MWh in 2012.

For most of the year, natural gas prices in New England and much of the nation were at their lowest levels in nearly two decades.

More: *ISO-NE*

INDIANA

NIPSCO Reaches Settlement For Infrastructure Plan

Northern Indiana Public Service Co. has reached a settlement agreement that would allow it to proceed with a $1.25 billion seven-year infrastructure-upgrade plan. The utility originally sought $1.33 billion.

NIPSCO reached the settlement with its industrial customers, the Office of Utility Consumer Counselor, the LaPorte County Board of Commissioners and the Indiana Municipal Utility Group. Infrastructure upgrades include pole replacement,

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installation of underground cables and replacement of substation transformers and breakers. NIPSCO has also committed to retrofitting utility-owned streetlights with LED bulbs and splitting the cost between customers and municipalities.

The company has filed the settlement with the Utility Regulatory Commission.

More: *Zacks*

LOUISIANA

PSC Reverses Course, Approves Cleco Purchase

The Public Service Commission reversed itself and voted to permit the $4.9 billion sale of Cleco to a consortium led by foreign investors. Cleco agreed not to raise its rates until 2020, and the utility's 286,000 customers also would receive credits averaging $500 each for the next few years.

"I think we did a pretty good deal," said Commissioner Foster Campbell, who flipped his position after negotiating from the dais during the hearing. The PSC had rejected the transaction in February, but the purchase will now close sometime in this month.

Three of the five elected PSC members were needed to approve the sale to a group led by Macquarie Infrastructure and Real Assets and British Columbia Investment Management Corp. In the end, four of the commissioners voted to approve the transaction.

More: *The Advocate*

MAINE

Bill to Save Biomass Plants Called Costly

A proposed law aimed at saving the state's ailing biomass energy plants would save logging industry jobs but could add millions of dollars to electricity bills.

The bill would require the Public Utilities Commission to seek competitive bids and negotiate contracts for 80 MW of renewable energy for five years. Central Maine Power said the measure could add up to $48 million to ratepayers' bills. The utility said that biomass plants have received more than $2.6 billion in ratepayer subsidies over the past 20 years, and despite that, half of them have closed since the 1990s because they weren't competitive.

A logger group has estimated that the complete loss of the biomass industry in the state would cost 400 jobs at the biomass plants and at least another 900 related jobs. Total economic losses to the state could be as high as $300 million per year, the group says.

More: *Portland Press Herald*

MARYLAND

2 Large Solar Projects Headed for Delmarva Peninsula

Seattle-based Longview Solar has proposed building two solar projects on Worcester County farm land that together would generate up to 35 MW.

Longview, a partnership between Elemental Energy and Tuusso Energy, says one of the projects, estimated at $20 million, would involve 63,000 solar panels on 125 acres east of Snow Hill. The other would be located west of Berlin, cost $30 million and feature 85,000 panels on 190 acres.

More: *DelmarvaNow*

MASSACHUSETTS

Landowners Rail Against Pipeline

Landowners last week complained to the Department of Public Utilities at a public hearing about Kinder Morgan's proposal to take rights of way by eminent domain along the proposed route of its Northeast Energy Direct natural gas pipeline.

Kinder Morgan has identified 39 Berkshire County properties for compulsory land surveying because owners have refused access.

"This is about corporate greed at its most despicable; it is not about the greater good," said landowner Williams Spaulding, who said he has filed numerous "no trespass" orders against the company but has still had to chase employees off his land.

More: *The Berkshire Eagle*

MICHIGAN

Exelon Wind Farm Bypasses Moratorium

A Marion Township moratorium to delay wind projects won't impede the proposed wind farm that inspired the moratorium in the first place.

Opponents of Exelon's proposed 68-turbine project in Marion, Bridgehampton and Custer townships had persuaded the Marion Township Board of Trustees last week to approve the moratorium that will halt all future wind development projects. But the 150-MW Exelon project was not included in the moratorium, officials said, because it already had been approved.

"I feel the board lied to and misled the citizens of Marion Township," said Jennie Schumacher, a wind farm opponent who organized a protest at the local board meeting.

More: *The Times Herald*

Report: DTE Coal Plants Worsen SW Detroit Air

Industrial air pollution is imposing health risks on low-income and minority residents in Southwest Detroit and the surrounding areas, *Newsweek* reported. The region does not comply with federal sulfur dioxide standards under the Clean Air Act. More than 15% of adult Detroiters have asthma, 29% more than the statewide average, recent state data shows.

DTE Energy operates two coal-fired power plants that are the biggest sulfur dioxide emitters in the area. A Marathon Oil refinery also contributes emissions, and the Michigan Department of Environmental Quality is close to granting the refinery a new permit that will allow it to emit an additional 22 tons of sulfur dioxide annually.

Lynn Fiedler, a MDEQ spokeswoman, says the department has been working with companies to bring emissions down, but it's a "difficult negotiation" because they will likely need to install costly carbon-reducing equipment. Fiedler added that DTE is "reluctant" to take steps in emissions-reduction.

More: *Newsweek*

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MISSOURI

PSC Staff Official Blasts Proposed Ameren Rate Scheme

Public Service Commission Staff Director Natelle Dietrich disparaged a proposal that would make it easier for Ameren to raise rates to pay for grid upgrades, calling it a "radical departure" from the current rate-setting procedure.

In testimony before the House Energy and the Environment Committee, Dietrich said the plan could increase residential rates by 62.1% over 10 years and boost industrial rates up to 94%. The rate scheme would also give Ameren's biggest customer, Noranda Aluminum, power to negotiate rates in order to keep the troubled smelter afloat.

A group of large industrial customers, including Nestlé-Purina, Doe Run, Ford, General Motors, Monsanto and Anheuser-Busch, urged the state to stay with the current rate system. "Toss this bill on the scrap heap," said Steve Spinner, representing the industrials.

More: St. Louis Post-Dispatch

MONTANA

PSC Orders Northwestern to Refund State's Customers $8.2M

State regulators last week ordered NorthWestern Energy to refund $8.24 million that it charged to buy electricity on the open market during a six-month outage in 2013 at the Colstrip coal plant. The Public Service Commission said that NorthWestern failed to take prudent actions to protect customers against the financial exposure from such a massive outage.

The majority of commissioners said the utility should have taken out insurance or pursued legal action against the plant operator to recover some of the costs incurred during the outage, which occurred when equipment malfunctioned following maintenance work at one of Colstrip's four units.

More: The Associated Press

NEBRASKA

Despite National Trends, Coal Still No. 1 in State

Pope

Federal forecasters anticipate that natural gas will surpass coal in 2016 as the nation's largest fuel source for power generation, but coal remains king in the state. Coal fueled 61.5% of electricity produced last year while natural gas made up 1%.

"It really does boil down to dollars and cents," said Nebraska Public Power District CEO Pat Pope. The average cost of coal delivered for power generation in the state was $1.34/MMBtu in December, making it the cheapest in the nation and about 30% less than the national average. Natural gas delivered in the state cost $3.44/MMBtu, more than 2.5 times more than coal.

More: Lincoln Journal Star

NEW YORK

NYISO Names New Board Members

Sadowsky

NYISO has selected Jane Sadowsky and Bernard Dan to fill vacancies on its Board of Directors, effective this month.

Sadowsky is the managing partner at Gardener Advisory, which provides consulting and advisory services predominately in the electricity power sector. Dan is the former CEO of Sun Holdings, a proprietary trading company that focuses on electronic trading of U.S. and European shares as well as currencies.

"Jane Sadowsky and Bernard Dan bring a wealth of talent and experience to our board," said Michael Bemis, board chairman. "Their proven leadership and combined expertise in the areas of energy finance, financial markets and business strategy will be instrumental in guiding the NYISO Board of Directors as we continue to advance the efficiency of our markets while reliably meeting consumers' energy needs."

More: NYISO

NORTH DAKOTA

Wind Farm Hearing Lasts for 12 Hours

More than 150 people gathered for a 12-hour Public Service Commission hearing about the controversial, 87-turbine Brady Wind Energy Center in Stark County.

For the bulk of the day, attorneys for both Brady Wind, a subsidiary of NextEra Energy, and the grassroots Concerned Citizens of Stark County group, questioned witnesses about the wind farm and the effects on the area. Public commenters pushed the hearing into the evening. Commissioner Brian Kalk said it was the longest hearing he's experienced in his eight years on the commission.

The PSC may take up to two months to make the final decision on the 150-MW wind farm, which was first proposed in late 2015.

More: The Bismarck Tribune

OKLAHOMA

Commission Asks OG&E to Include DG in Rate Case

The Corporation Commission says distributed generation and its effect on the grid should be explored in Oklahoma Gas & Electric's pending $92.5 million rate case.

OG&E included a distributed generation tariff in its rate filing to comply with a 2014 law that requires utilities to establish a separate class for distributed generation customers if they can show those customers are not paying their fair share of grid-connection costs. The utility wants to establish a $2.68/kW demand charge for residential and small commercial customers. With the average peak demand for a residential customer at 6 to 8 kW, the demand charge could be $16-21 per month.

A hearing in the rate case is expected to begin May 3.

More: The Oklahoman

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STATE BRIEFS

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OG&E Seeks Approval For Sooner Scrubber

Oklahoma Gas & Electric next month will make a third attempt to win regulatory approval for a $500 million scrubber project at its Sooner coal-fired plant.

The Corporation Commission last year rejected a more comprehensive, $1.1 billion case and a pared-down modification of the utility's environmental compliance plan. OG&E has asked for a rehearing and says it needs a decision by May 2 to meet a series of engineering and construction deadlines if the scrubbers are to be installed.

The utility is arguing for coal generation to remain a significant part of its fuel portfolio, while critics question why OG&E wants to keep a 35-year-old coal plant running for another 30 years when market and environmental forces are turning against the fuel.

More: *The Oklahoman*

PENNSYLVANIA

Plan to Generate Power From Tires Scrapped

A company that had planned to build a $360 million, 90-MW plant to generate electricity from old tires instead will partner with a high-tech firm to develop a facility to make diesel fuel and other products from the material.

Crawford Renewable Energy said it changed tack because a drop in the wholesale price of electricity made the Greenwood Township power plant proposal "economically unfeasible."

The newly proposed non-combustion facility would recycle the tires into carbon black, a component in photocopier toner, and into the type of low-sulfur diesel required by the federal government for trucks and other heavy vehicles.

More: *The Meadville Tribune*

RHODE ISLAND

National Grid Substation Construction Started

National Grid has started construction on a new substation that will improve electricity delivery to downtown Providence and the South Street Landing project.

The new substation will replace one dating to 1919. It is expected to be completed late in 2017.

"This facility will meet the electric demands of a major portion of the city for the immediate future and beyond," said National Grid Rhode Island President Timothy F. Horan.

More: *Providence Journal*

Plant Would Scuttle Emissions Regulations

A Brown University professor is arguing that the construction of a new natural gas-fired power plant in Burrillville would make it impossible for the state to meet its target for reducing carbon emissions in the coming decades.

J. Timmons Roberts, who helped write the state's climate change regulations, says building the 900-MW Clear River Energy Center conflicts with the Resilient Rhode Island Act, the 2014 law that set a non-mandatory goal of reducing state greenhouse gas emissions 80% below 1990 levels by 2050.

Roberts is submitting the testimony on behalf of the Conservation Law Foundation, a regional environmental group that is opposed to the power plant, which was proposed last year by Invenergy.

More: *Providence Journal*

VERMONT

Digester Generating Heat at the Farm

Opponents of a proposed electricity-producing manure digester in St. Albans say the project would jeopardize the wetlands that it ostensibly is designed to protect.

Green Mountain Power has applied to the Public Service Board for a Certificate of Public Good for the digester, which supporters say is a proven agricultural technology for improving water quality and reducing emissions of methane from dairy farms and compost operations. Green Mountain says its digester is the only one in the state that includes advanced systems for removing phosphorus from manure slurry.

But a vocal critic, Tim Camisa, co-owner of St. Albans-based Vermont Organics Reclamation, says the project would be located only 200 feet from a stream, too close to protect the streambank and wetlands from accidents.

More: *Burlington Free Press*

VIRGINIA

SCC Greenlights Dominion Natural Gas-Fired Plant

The State Corporation Commission has approved Dominion Virginia Power's plan to build a natural gas-fired power plant in Greensville County.

Construction is expected to begin this year on the $1.3 billion plant, which would generate 1,588 MW and be situated on 55 acres.

The company said customers will save $2.1 billion over the life of the plant through fuel savings compared with the cost of buying power on the open market.

More: *PennEnergy*

WYOMING

Wind Tax Revenues Down, Cause Unknown

State tax revenues from wind energy fell by 15% in 2015, coming at a time when the state is already suffering the effects of a pronounced downturn in the oil, natural gas and coal sectors. The reason for the 2015 tax decline was not immediately apparent.

The Cowboy State became the first in the nation to tax wind production when it approved a $1/MWh levy in 2010. Tax collections have varied between $2.6 million in 2012, the first year the levy was imposed, to $4.4 million in 2014. Last year, the state collected $3.7 million.

The state's wind production capacity has remained unchanged since 2010. A lack of transmission capacity has stymied further development in the state.

More: *Casper Star-Tribune*

FERC Action Awaited Following PUCO OK on PPAs

Continued from page 1

asked FERC on March 21 to expand PJM's minimum offer price rule to prevent state subsidized plants from making below-cost offers that would suppress capacity prices (EL16-49). (See *Generators to FERC: Expand MOPR for Subsidized FE, AEP Plants*.)

The companies have asked FERC to rule before PJM's next Base Residual Auction, which begins May 11.

Since PUCO's ruling, seven organizations, including the Pennsylvania Public Utility Commission, the PJM Power Providers Group and CPV Power Holdings, have filed to intervene in the cases. On Monday, FERC denied AEP and FirstEnergy's request for more time to respond to the MOPR filing, leaving the April 11 comment deadline intact.

PUCO's approval appears to have had little effect on Wall Street. AEP has risen just 53 cents (0.8%) from Thursday's open, closing Monday night at $66.58. FirstEnergy has dropped 37 cents (1%), closing at $35.68.

Sale Likely?

Guggenheim Securities analyst Shahriar Pourreza said in a research note Thursday that he expects AEP to sell the remaining 5 GW of generation not covered by the PPAs, "a path for the company to move toward a fully regulated business profile."

"We estimate the sale could generate $1.9 [billion to] $2.3 billion, which we expect to be redeployed into transmission to offset lost earnings," Pourreza wrote.

For FirstEnergy, Pourreza said, the PPAs will strengthen its balance sheet without requiring the issuance of additional equity. "We see FE as a turnaround story with the PPAs approved," he wrote.

The analyst said FERC is unlikely to change PJM's MOPR "to apply specifically to AEP and FE's plants." The MOPR plaintiffs have asked FERC to order PJM to develop a long-term solution by Nov. 1.

'Rate Stability'

In approving the eight-year PPAs, Ohio regulators said they were striving for "rate stability" by building in safeguards intended to protect consumers, modifying the plans to limit bill increases. The commission also added provisions meant to "encourage" grid modernization and retail competition.

"The commission's order strikes an appropriate balance between consumers' interests in cost-effective electric service and diverse stakeholder interests," Chairman Andre Porter said. "Today's opinion and order affirms Ohio's commitment to encourage a modernized grid and retail competition."

Although the PPAs guarantee the generators receive revenue streams above current market prices, AEP and FirstEnergy contend the deals will save customers money if natural gas prices increase.

"The Public Utilities Commission of Ohio recognized the significant benefits of this plan for Ohio consumers. This plan will ensure more stable electricity prices in Ohio and promote the development of new, renewable generation to support the state's economy," AEP CEO Nick Akins said in a statement.

W.H. Sammis plant *Source: FirstEnergy*

"Today's decision will help protect our customers against rising electric prices and volatility in the years ahead, while helping to preserve vital baseload power plants that serve Ohio customers and provide thousands of family-sustaining jobs in the state," FirstEnergy CEO Charles E. Jones said in a statement.

Opponents Denounce PUCO Ruling

Opponents of the plan were quick to respond to the decision.

"Today the PUCO failed more than 100,000 Ohioans who opposed the multi-billion

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Stakeholders React to MISO Proposed Auction Design

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Instead, the RTO plans to examine system-wide import capability. And while the grid operator does not intend to impose a minimum offer price rule, it would update its Tariff with a bright line reliability test for forward procurement.

Multiple stakeholders asked what data and forecasting methods MISO would use to calculate local clearing requirements three years into the future, questions that Bladen deferred to the April RASC. "We'll need to discuss that with stakeholders in a little more detail," he said.

Bladen also said the RASC could best address the concerns of stakeholders who think the FLRA will produce extremely low prices and want MISO to run simulations and present the results. Price formation is "something we've given extraordinary amounts of attention to," he said.

"This might work for a partially deregulated zone, but this won't work for a zone that's been fully deregulated," said Exelon's Marka Shaw, who asked for another CRSTT meeting specifically focused on affected Illinois customers. "I don't like the idea of this rolling into the RASC and this getting shortchanged given the tight timeline."

David Sapper of Customized Energy Solutions wanted to know how generators could use the five-year FLRA opt-in to participate, but Bladen clarified that the opt-in applies only to load-serving entities, not generators.

In response to a question about how MISO's new two-season construct would align with forward procurement, Bladen said seasonal constructs — currently scheduled to be enacted in the 2018/19 planning year — would apply to the FLRA as well.

"These filings are effectively being looked at in parallel," Bladen said.

Jim Dauphinais, counsel for Illinois Industrial Energy Consumers, asked how the downward sloping demand curve would apply to market supply. Bladen stressed the curve is only applicable to the demand — not the supply — side of the auction.

"It is very feasible to have different purchase price sensitivities for different consumers, if you will, in the same market," Bladen said.

FERC Action Awaited Following PUCO OK on PPAs

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dollar FirstEnergy and American Electric Power bailouts," said Rachael Belz, executive director of Ohio Citizen Action. "Ohioans don't want utilities raiding their pockets to prop up 18th-century technology in a 21st-century world."

"The Alliance for Energy Choice is dismayed that the PUCO did not reject outright FirstEnergy's and AEP's demands to force consumers to pay unnecessary, additional electric charges of at least $6 billion over eight years," the competitive energy supplier group said in a prepared statement.

"Anything short of rejection damages markets and competition," tweeted former Pennsylvania PUC Commissioner John Hanger, now a private energy industry attorney. "Good for crony capitalism."

Rate Freeze

The two utilities sought the long-term PPAs to provide guaranteed income for plants facing competition from cheaper gas-burning plants. Both companies had earlier reached settlements with PUCO's staff and others, leading to Thursday's rulings by the commission.

AEP's plan calls for guaranteed income for the company's 2,671-MW ownership share of nine plants, as well as a 423-MW contractual share of Ohio Valley Electric's generating fleet, until May 2024.

FirstEnergy's agreement provides similar guarantees for its 908-MW Davis-Besse Nuclear Power Station, the 2.2-GW W.H. Sammis coal-fired plant and the company's 105-MW share of Ohio Valley Electric's generation.

In both cases, ratepayers would make the generating units whole if capacity and energy sales in the competitive market were not sufficiently profitable. While the companies testified that the market would eventually prove profitable for their plants, the Ohio Consumers' Counsel said the plans left consumers open to excess costs that could top $8 billion over the life of the deals.

"FirstEnergy's Ohio utilities expect to file new rates with the PUCO by May 2, following the completion of a competitive auction process to buy electric generation supply for their non-shopping customers," FirstEnergy said in a press release. "FirstEnergy expects that the vast majority of its Ohio utility customers will see lower total bills after these auctions."

But Todd Snitchler, former PUCO chairman and now with The Alliance for Energy Choice, said FirstEnergy's claim of static or lower bills is disingenuous.

"It's not out of the goodness of their hearts," he scoffed. "It's because that's what the commission said."

PUCO's order freezes FirstEnergy's base distribution rates during the PPA and ensures that average customer bills will not increase for the first two years.

PUCO's order on AEP limits rate increases to 5% during the first two years of the PPA. The company also promised $100 million in rate credits to reduce increases during the final four years.

Both companies originally requested 15-year PPAs, but they scaled back those requests in the face of opposition from consumer advocates and other merchant generators. The companies worked behind the scenes to construct settlements with some of the opposition, adding environmental incentives and consumer protections in exchange for their approval.

AEP won over the Sierra Club with a promise to double the state's wind generation and nearly quintuple its solar capacity — translating into 900 MW of new renewable energy.

Criticism from All Sides

Critics see the agreements as an attempt at re-regulation in a deregulated Ohio electricity market, coming after the generating companies were already provided stranded cost compensation to give up their monopolies. FirstEnergy, for instance, was compensated for $6.9 billion in stranded costs in 1999.

But the companies say that times have changed and that the PPAs are crucial for keeping the plants operating and Ohioans employed.

The companies' proposals were immediately met with protests from environmentalists, ratepayer advocates and rival generators in PJM, with Dynegy and Talen Energy threatening litigation to block the agreements. (See *Merchant Generators Lead Opposition to FirstEnergy-Ohio Settlement*.)

Even Exelon, which is seeking a similar deal for its own nuclear stations in Illinois, came out against FirstEnergy, and upped the ante by offering its own offer to Ohio. It called on PUCO to reject the FirstEnergy plan as "grossly lopsided" and offered to supply the 3,000 MW covered in the PPA with its own generation, at a proposed $2 billion savings to Ohio consumers.

CFTC Exempts Capacity Purchases, Gas Peaking Contracts from Swap Rules

The Commodity Futures Trading Commission proposed Monday that electric capacity purchases and natural gas peaking supply contracts be exempt from regulation as swaps.

The commission unanimously approved proposed guidance that said such contracts should not be considered swaps under the Commodity Exchange Act because they are "customary commercial arrangements" intended to meet regulatory commitments. The commission will accept comments on its proposal for 30 days.

"These contracts are entered into to assure availability of a commodity, not to hedge against risks arising from a future change in price of that commodity or for speculative or investment purposes," Chairman Timothy Massad said in a statement supporting the guidance. "They are typically entered into in response to regulatory requirements, the need to maintain reliable energy supplies and practical considerations of storage or transport."

The exemptions apply to:

- Load-serving entities' contracts to purchase electric capacity to comply with state or federal resource adequacy rules; and
- Peaking supply contracts that allow an electric utility to purchase natural gas from another provider if its local distribution company curtails its delivery in order to preserve fuel for heating customers.

Massad said the proposed guidance, which complements the commission's final rule regarding trade options, "will reduce burdens on end users and allow them to better address commercial risk."

— Rich Heidorn Jr.