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Besieged CPUC Denies SDG&E Wildfire Recovery

Commission Under Fire over Safety, Ethics

By Jason Fordney

Utilities are at the epicenter of public battles between the California Public Utilities Commission and its critics over wildfires, public safety and ethics that have major financial implications for companies and ratepayers.

Those controversies surfaced at a Nov. 30 CPUC meeting at which the commission denied San Diego Gas & Electric's request to recover from ratepayers $379 million in costs related to the 2007 Southern California wildfires. SDG&E quickly vowed to vigorously fight the commission's unanimous decision.

Following recommendations by an administrative law judge, the CPUC said the utility "did not reasonably manage and operate its facilities prior to the 2007 Witch, Guejito and Rice Wildfires," which killed two people and destroyed homes and property. SDG&E's $379 million request was separate from other court proceedings, settlements, insurance payments and federal cost recovery regarding the fires.

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NERC Parts Ways with Chief Security Officer

Sachs Forced out, Sources Say

By Rich Heidorn Jr.

Just days after losing its CEO, NERC has seen another senior management departure.

Senior Vice President and Chief Security Officer Marcus Sachs, one of seven direct reports to NERC's CEO, "resigned" effective Nov. 27, the organization said in a statement.

However, three sources knowledgeable about the matter said Sachs was forced to leave. One former NERC staffer said Sachs was ousted because of concerns by industry officials on the Electricity Subsector Coordinating Council (ESCC) that he lacked the background to lead the planned expansion of the Electricity Information Sharing and Analysis Center (E-ISAC).

"The ESCC didn't have confidence in him taking the ISAC forward," the former staffer said. "I don't know if it was GridEx-related; I don't know if it was storm-related or that Marc came from a communications background."

Sachs joined NERC in May 2015 from Verizon, where he was vice president of national security policy. Prior to Verizon, he was

Marcus Sachs at NARUC's winter meetings in February 2016. | *© RTO Insider*

deputy director of the computer science lab at SRI International and the founder of a computer security consultancy. He also worked for several months as cyber program director at the U.S. Department of Homeland Security and served more than 20 years in the U.S. Army. He has degrees in civil engineering and computer science in addition to a Ph.D. in public policy.

A second former NERC official said he was told Sachs was fired but that he didn't know the reason. "All I heard was that NERC forced him out," the ex-staffer said. "My understanding is his departure was very sudden."

But the first ex-staffer said the resignation "was supposed to be in the works before"

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Mexico Market Director Seeks Increased Participation

By Tom Kleckner

MEXICO CITY — A top official with Mexico's wholesale electricity market accepted praise last week for the outcome of the country's latest capacity auction, but he said he is still intent on increasing participation in the effort.

Marcos Valenzuela | *© RTO Insider*

"There are barriers to true efficiency in the market," Marcos Valenzuela, director of the National Energy Control Center's (CENACE) wholesale market, said during a Gulf Coast Power Association breakfast Nov. 30. "I think we need to incorporate more participants, more qualified suppliers, to give more offers to the end users."

Valenzuela, one of three top directors for CENACE, made his comment after telling his audience that competition had helped narrow offer spreads and drive down prices

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IN THIS WEEK'S ISSUE

Correction

An article in the Nov. 28 issue failed to note that New York Public Service Commissioner Diane Burman had dissented on an order concluding the PSC's Energy Efficiency Portfolio Standard (EEPS). It also improperly prefaced a quote from the commissioner by saying "the commission had learned" from EEPS. In fact, Burman said "we must learn from EEPS" the need to be more prudent and measured in making demands. (See *NY Fine-tuning CES; Phasing out EE Program*.)

COUNTERFLOW
BY STEVE HUNTOON

Grid Batteries & Kool-Aid, Once More with Feeling

By Steve Huntoon

Huntoon

I'm taking a break from trashing the Department of Energy's Notice of Proposed Rulemaking to return to another of my favorite punching bags: grid batteries.

Sorry, I Lied a Little

But before punching grid batteries again, can I drive another stake in the heart of the DOE proposal?[1] It's a PJM press release from last week.[2] Here are a couple of my favorite sentences (emphasis added):

"Mild or severe weather, no matter what the winter brings, we are prepared and expect to have *more than enough* power available to meet consumers' demand for electricity." And: "PJM expects to have *184,926* MW of electric resources to meet the forecasted peak demand of *135,526* MW." By my math, that's about *50,000 MW to spare, the equivalent of 60 large power plants.*

So consumers should pay billions to subsidize clunkers and destroy markets that work?

It's not too late for Energy Secretary Rick Perry to say "never mind." Not that I'm holding my breath.

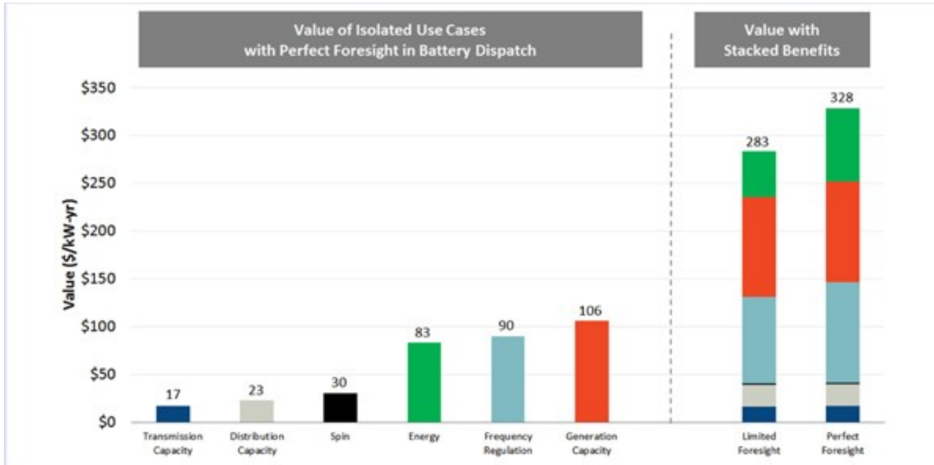
Back to Grid Batteries

OK, where was I? Oh yeah, grid batteries.

The Brattle Group recently joined the herd for "stacking" (adding) the values of batteries for different functions.[3] The study, even called "Stacked Benefits," finds that the stacked values are equal to or more than the cost of batteries.

This conclusion then prompts the search for "barriers" to batteries — if they're so darned valuable, why aren't more getting deployed? And this relative inactivity then supports a call for mandates and subsidies so that the supposedly true economic outcome is imposed by fiat.

Yikes, didn't I puncture the battery fantasy a couple years ago? Yes, I did.[4]



| The Brattle Group

But let's hit the high points again. I will try to be succinct.

The figure from the Brattle study above is what we'll focus on.

Brattle adds up almost all of the individual "values" left of the dotted line to get the total "Value with Stacked Benefits" to the right.

There are at least four screaming errors in the Brattle analysis: (1) adding energy arbitrage value and generation capacity value, (2) energy arbitrage value, (3) generation capacity value and (4) magnitude of frequency regulation market.

Adding Energy Arbitrage and Capacity Values

As I pointed out in the earlier article, a battery can provide energy arbitrage value or capacity value — *but not both*. This is not rocket science.

A battery cycled daily for energy arbitrage is going to be partially or totally discharged most of the time, and thus cannot be relied upon to provide its rated capacity on demand in the event of a capacity emergency. It's just that simple.

Some may claim that the need for capacity will neatly match up with the highest energy prices, so that a battery can be assumed to be discharging when capacity is most needed. This is just wrong.

To see why, please take a look at the chart of actual capacity emergencies in PJM below.[5]

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Date	Performance Region	Emergency Procedure	Start Time (EPT)	Stop Time (EPT)	Number of Performance Assessment Hours
March 4, 2014	PJM RTO	Emergency Load Management	5:30 AM	8:30 AM	4
January 30, 2014	Mid-Atlantic Dominion (MAD)	Maximum Emergency Generation Action	5:51 AM	9:07 AM	5
January 30, 2014	PJM RTO	Voltage Reduction Warning	6:50 AM	7:35 AM	2
January 24, 2014	Mid-Atlantic Dominion (MAD)	Emergency Load Management	5:30 AM	8:45 AM	4
January 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Emergency Load Management	3:00 PM	7:00 PM	4
January 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Emergency Load Management	5:30 AM	8:30 AM	4
January 8, 2014	PJM RTO	Emergency Load Management	6:00 AM	7:00 AM	1
January 7, 2014	PJM RTO	Emergency Load Management	4:00 PM	6:16 PM	3
January 7, 2014	PJM RTO	Primary Reserve Warning	12:55 AM	12:14 PM	13
January 6, 2014	PJM RTO	Voltage Reduction Warning	7:27 PM	9:23 PM	3
September 11, 2013	Mid-Atlantic Dominion (MAD)	Emergency Load Management	2:00 PM	6:30 PM	5
July 18, 2013	PJM RTO	Emergency Load Management	2:40 PM	6:00 PM	4
July 18, 2012	Mid-Atlantic	Voltage Reduction Warning	2:40 PM	3:30 PM	2
July 18, 2012	Mid-Atlantic	Emergency Load Management	3:22 PM	5:34 PM	2
July 17, 2012	PJM RTO	Emergency Load Management	3:08 PM	7:05 PM	5
July 22, 2011	PJM RTO	Emergency Load Management	1:30 PM	7:37 PM	7
June 9, 2011	Mid-Atlantic	Primary Reserve Warning	3:54 PM	6:15 PM	4

Capacity emergencies | *PJM*

COUNTERFLOW
BY STEVE HUNTOON

Grid Batteries & Kool-Aid, Once More with Feeling

Continued from page 3

Please note from the far right column all the emergencies that lasted more than four hours. A battery with four hours of maximum discharge — like that of the sponsor of the Brattle study — cannot possibly provide its rated discharge capacity for more than four hours.

And even for emergencies of four hours or less, a battery discharging for four hours of maximum energy price would have discharged prematurely for two other emergencies, and thus not been able to cover the emergency period.

In other words, batteries would have failed to provide reliability in seven of the 17 emergencies (these seven are highlighted). And this generously, and unrealistically, assumes that the battery operator could each day predict the four highest-priced hours (supposedly the highest-risk hours) of the next day — which it can't as discussed later.

Now let's look at the individual benefits that Brattle stacks up.

Energy Arbitrage Value

For energy arbitrage, even in what it calls the "Limited Foresight Case," Brattle assumes that the battery operator can, each day, predict the four highest-priced hours of the next day for discharge, and pick the lowest-priced hours of the next day for charging.[6]

This is not possible. There is no forward hourly energy market revealing day-ahead prices in advance. Brattle should have simulated a realistic *attempt* to forecast the highest- and lowest-priced hours, and then used the actual day-ahead prices at those hours to estimate energy arbitrage revenue.[7]

Generation Capacity Value

The discussion above about adding energy and capacity value applies here as well. A four-hour battery simply can't provide capacity value because capacity emergencies often are longer. (Of course, a battery shouldn't need to have 90 days of charge like the DOE proposal implies, but definitely more than four hours.)

Frequency Regulation

Brattle is correct that a battery can provide frequency regulation. But what Brattle leaves out is that frequency regulation is a small niche market that, for example, is already saturated in PJM. And that a battery providing frequency response can't provide other benefits like energy arbitrage at the same time — no multitasking!

And From the Land Down Under

I suppose this is as good a place as any to lambaste the media hype around the Tesla battery project in South Australia. The blackout precipitating that project had nothing to do with inadequate resources.[8] The events in the blackout involved many hundreds of megawatts, whereas the Tesla battery is only 100 MW of capacity. And its 129 MWh of energy means it would last for little more than an hour.

Last week, after the battery was energized, *The New York Times* led the media fawning, calling it "one of this century's first great engineering marvels." Can anyone seriously compare stringing together a bunch of off-the-shelf battery cells with, say, the tallest building in the world (Burj Khalifa), the biggest dam in the world (Three Gorges Dam), the tallest bridge in the world (Millau Viaduct), the Mars rovers, the mapping of the human genome, the Large Hadron Collider, smartphone proliferation, Wi-Fi proliferation, 3D printing, re-floating of the Costa Concordia, Bluetooth, ride-sharing, home-sharing, Google — all marvels of this century? C'mon *Times*, get a grip.

And in the category of "you can't make this stuff up": The day after the battery was brought online, bad weather brought down power lines causing blackouts in areas around the battery.[9] The battery was no help.

Bottom Line

Grid batteries aren't useless. They are an excellent way to separate utility customers from their money. And they come in shiny boxes.

Steve Huntoon is a former president of the Energy Bar Association, with 35 years of experience advising and representing energy companies and institutions. He received a B.A. in economics and a J.D. from the University of Virginia. He is the principal in Energy Counsel, LLP, www.energy-counsel.com.

[1] If you're interested in my five prior columns trashing the DOE proposal, they're available in gruesome detail here: http://www.energy-counsel.com/recent-publications.html.

[2] http://pjm.com/-/media/about-pjm/newsroom/2017-releases/20171129-winter-readiness-release.ashx.

[3] http://www.brattle.com/system/publications/pdfs/000/005/494/original/Stacked_Benefits_-_Final_Report.pdf?1505226490.

[4] http://www.energy-counsel.com/docs/Battery-Storage-Drinking-the-Electric-Kool-Aid-Fortnightly-January-2016.pdf.

[5] http://pjm.com/-/media/committees-groups/committees/elc/postings/performance-assessment-hours-2011-2014-xls.ashx?la=en (highlighting added and footnotes omitted).

[6] "In the Limited Foresight case, the battery is operated with realistic constraints around the ability to predict prices. Specifically, the battery dispatch schedule is optimized across all [day-ahead] value streams *with perfect foresight into prices over the next 24 hours*." (page 8, emphasis added).

[7] It is important to note as well that efficiency losses are uncertain and vary widely by battery technology. And typically the reported efficiency factors do not include "parasitic load" (cooling system, etc.) which can significantly reduce actual system efficiency. http://www.networkrevolution.co.uk/wp-content/uploads/2014/12/CLNR_L163-EES-Lessons-Learned-Report-v1.0.pdf (page 38).

[8] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

[9] http://www.theaustralian.com.au/news/south-australia-storms-power-blackouts-as-tesla-battery-is-turned-on/news-story/de20d9518b40191381e9534eca722980

CAISO NEWS

Thumbs Up/Down for CAISO Gas Constraint Measures

By Robert Mullin

FERC last week approved CAISO's request to extend temporary market measures instituted last year in response to natural gas pipeline restrictions stemming from the 2015 closure of the Aliso Canyon gas storage facility.

But the commission rejected the ISO's proposal to make other gas-related measures permanent throughout the ISO and the Western Energy Imbalance Market (EIM), in addition to the Southern California region affected by the gas constraints (ER17-2568).

Aliso Canyon was cleared to resume normal operations in July, but is still operating at reduced capacity. CAISO sought to implement the permanent Tariff provisions to prepare for potential operational issues in other areas it oversees. (See *Plan Would Apply Aliso Canyon Measures Across CAISO, EIM*.)

In its ruling Nov. 28, FERC accepted the ISO's bid to extend a measure allowing Southern California generators to reflect gas cost expectations in day-ahead bids by using an approximation of next-day gas prices, which are published after the ISO's day-ahead market runs. ISO rules typically require generators to incorporate the previous day's gas prices into energy bids.

Aliso Canyon | *California Office of Emergency Services*

The commission also approved continued use of a gas adder and an after-the-fact cost recovery mechanism for generators connected to the Southern California Gas system to tie cost recovery and penalties to same-day gas prices rather than day-ahead gas indices.

"As CAISO reports, Aliso Canyon will continue to experience limited operability for the foreseeable future, which presents the risk of curtailments to gas-fired generators and, potentially, the interruption of service to load," the commission said. "We find that continuation of the interim measures for an additional year should improve scheduling coordinators' ability to manage their gas procurement and enhance their ability to recover gas procurement costs, while also providing CAISO with flexible tools to maintain reliability and avoid adverse market outcomes related to the limited operability of Aliso Canyon."

The temporary provisions will remain in effect until Nov. 30, 2018.

Gas Burn Cap

FERC rejected CAISO's proposals to make other interim measures permanent and to extend their application to the EIM. Chief among them was the ISO's proposal to limit the amount of gas that generators can burn during periods of restricted gas supply.

Within its own balancing authority area, the provision would have allowed CAISO to develop the constraint on its own motion, then require it to publish details about the constraint and provide market participants an opportunity to comment.

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SoCalGas Pipeline Losses Spur Curtailment Warnings

By Jason Fordney

The loss of three natural gas pipelines is creating major concerns about Southern California's gas and electricity supplies, with three state and local regulators saying that Los Angeles-area electricity generators could experience gas curtailments this winter.

The California Public Utilities Commission, California Energy Commission and Los Angeles Department of Water and Power (LADWP) last week issued a new assessment of the situation suggesting that curtailments are more likely this winter than last because of pipeline ruptures — but much will depend on the weather. Southern California Gas' Line 235-2 ruptured on Oct. 1 and also damaged Line 4000, adding to an existing outage of Line 3000, according to the report.

"Natural gas service is threatened to noncore customers, including electric generators, this winter," the report said. "This threat occurs even though there is more gas in storage than at this time last year."

The concerns arose even after SoCalGas' Aliso Canyon gas storage facility resumed injections in July, despite objections from state agencies. (See *Aliso Canyon Resumes Injections*.) Operations at the facility had been halted following a massive methane release detected in October 2015 and finally plugged in February 2016. The California Division of Oil, Gas and Geothermal Resources determined it is safe for the company to resume injections at the site.

The agencies issuing last week's report said that other actions under consideration include an emergency moratorium on new natural gas service connections in the Los Angeles County area served by Aliso Canyon.

"Another proposed measure would direct electricity generators to more frequently shift generation to facilities located outside the SoCalGas system to reduce gas use in December," the agencies said. "This could allow SoCalGas to preserve storage inventories deeper into the winter."

The report also said LADWP could delay electrical transmission upgrades until February in order to maintain access to power sources outside the region. The agencies are additionally considering slightly increasing the volume of gas that can be stored at Aliso Canyon.

CAISO NEWS

Besieged CPUC Denies SDG&E Wildfire Recovery

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Commissioner Liane Randolph said the SDG&E case turned on the specific question of equipment maintenance, including faults on a transmission line, a communications wire and vegetation management.

"There is no dispute that each of the fires were caused by SDG&E facilities," she said. Randolph noted the decision is not a final statement of the doctrine of inverse condemnation, the legal tool that SDG&E leaned on in its claim. The logic is that "the costs of a public improvement benefiting the community should be spread among those benefited rather than allocated to a single member of the community."

But Randolph said it is appropriate to put the costs on Sempra shareholders, not ratepayers, and the case has nothing to do with the utility's current management of the system. "The decision is specific to the 2007 incident and the facts of this case," she said.

Commissioner Clifford Rechtschaffen added that inverse condemnation "is somewhat of a theoretical issue in this matter."

"The decision does not hold the utilities to a standard of perfection," he said. "We can't apply a standard that provides an incentive for a utility to act imprudently or unreasonably," adding that would send the wrong signal to the utility.

| © RTO Insider

In a written statement, SDG&E Chief Regulatory Officer Lee Schavrien said: "SDG&E strongly disagrees with today's decision. The CPUC got it wrong. The 2007 wildfires were a natural disaster fueled by extreme conditions including the worst Santa Ana wind event this region has ever seen, combined with high heat, low humidity and hurricane-force winds as high as 92 mph."

During its third-quarter earnings call, SDG&E parent Sempra Energy vowed to take legal action if denied the cost recovery. (See *SDG&E's Wildfire Costs Undercut Sempra Profits*.) The commission did receive praise from The Utility Reform Network and the California Office of Ratepayer Advocates for denying the cost recovery.

During the meeting, commissioners also discussed the increased risk of fires attributed to climate change in California. PUC President Michael Picker noted that areas of elevated or extreme fire hazard are growing in California, to almost 42% of the

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Thumbs Up/Down for CAISO Gas Constraint Measures

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In the EIM, the ISO would have enforced constraints "at the request of and in coordination" with the relevant EIM balancing authority. The EIM currently includes Arizona Public Service, NV Energy, PacifiCorp, Portland General Electric and Puget Sound Energy.

In rejecting the proposal, the commission found that CAISO failed to demonstrate how it would a prevent an EIM entity from having "too much discretion" over the development and enforcement of a constraint. "This raises the concern that an EIM entity would be able to develop a constraint to help it manage gas supply issues of its affiliated resources while other market participants would have to rely on appropriate bidding and contracting," the commission wrote.

The commission also said that CAISO had not explained how it would monitor and enforce maximum burn constraints in the EIM, nor did it define the role of the relevant natural gas company within the Tariff.

Still, FERC left the door open for CAISO to develop a gas burn cap for its own BAA, saying such a measure could be a "useful tool" to help manage gas limitations "more efficiently than relying solely on manual dispatch."

The commission also rejected CAISO's proposals to make permanent two other interim measures: One allows the ISO to suspend virtual bidding in the face of gas constraints; the other permits it to release two-day-ahead advisory schedules to certain scheduling coordinators.

"These solutions may be appropriate for an interim Tariff provision to address an identified problem, such as Aliso Canyon's limited availability, but CAISO has not provided justification that they are appropriate or adequate in their current form as permanent features of CAISO's market," the commission said.

FERC acknowledged that its denial of the permanent Tariff changes would leave CAISO without some existing tools designed to address limited operations at Aliso Canyon.

"Our rejection of these permanent Tariff provisions does not foreclose CAISO from proposing an extension of these interim Aliso Canyon-specific Tariff provisions for an additional year, as CAISO did with the three Tariff provisions that we accept on a temporary basis in this order," the commission said.

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state, and more people are moving into those areas with higher wind and lightning.

"This is become an increasingly complex area for us," Picker said, adding that the decision "may or may not" set a precedent for future cases.

As the battle over the 2007 fires continues, the CPUC is preparing to evaluate a similar situation for Pacific Gas and Electric regarding the particularly destructive fires that ravaged California's wine country this summer, from which the death toll rose to 44 this week. The cause of the fires is still under investigation. (See *Wildfires Color California PUC Utility Decisions*.)

Embroiled in Controversy

The CPUC issued the ruling amid a swirl of legal battles, regulatory proceedings and public accusations that focuses heavily on the tenure of former President Michael Peevey, who resigned from the commission in January 2015 and has been under investigation by the state's attorney general for engaging in back-channel discussions with Southern California Edison over the financial terms of the San Onofre nuclear plant's closure.

The environment around the current CPUC has been increasingly darkened by years of public allegations of other ethics violations. State lawmakers last week renewed their call for Attorney General Xavier Becerra to file charges regarding improper communication between the PUC and PG&E concerning the 2010 explosion of the company's gas pipeline in San Bruno. The request came soon after the discovery of old email communications between the PUC and former PG&E consultant and Commissioner Susan P. Kennedy regarding the San Bruno settlement. (See *Probe Reveals More CPUC-PG&E Contacts on Pipeline Blast*.)

The situation led to a confrontation at last week's meeting between Picker and San Diego attorney Michael Aguirre, a frequent CPUC critic who is involved in the San Onofre case.

As Aguirre approached the microphone during the public comment period at the San Francisco hearing, Picker asked him if he was there to apologize for his "rude, abusive and disruptive behavior" at a recent hearing regarding the San Onofre plant. Aguirre ignored Picker and instead spoke of recent wildfire deaths, the San Bruno explosion and the natural gas leak at the Aliso Canyon storage facility near Los Angeles.

Aquirre said the victims of the Tubbs Fire in Napa and Sonoma Counties "are not here to ask why the California Public Utilities Commission did not enforce the safety rules against PG&E that could have saved our lives." Picker told Aguirre he himself was a party to one of the proceedings and his appearance might violate commission rules.

Commission Response

The commission on Dec. 1 issued a lengthy public statement saying, "The CPUC has cooperated with the attorney general's office through every step of the investigation as well as with federal investigators whose demands for documents preceded those of the attorney general. Throughout the process, the CPUC has produced more than 1 million documents to the attorney general."

The CPUC said the agency had fully complied with a search warrant as of December 2016. "The case is in the hands of the attorney general's office, and the next steps are up to the office," the commission said.

At its Nov. 30 meeting, the commission also voted to defer consideration of a related $86 million settlement between it, PG&E and other parties over improper *ex parte* communications in the wake of the San Bruno blast.

CAISO News

Hydro, Jointly Owned Coal Face EIM Challenges

By Jason Fordney

Regional Issues Forum participants (left to right): Kelcey Brown, PacifiCorp; Clay MacArthur, Deseret; Zach Sanford, Navigant; RIF Chair Cameron Yourkowski, Renewable Northwest; Therese Hampton, Public Generating Pool; and Matt Lecar, PG&E. | © *RTO Insider*

BOISE, Idaho — Integration into the Western Energy Imbalance Market (EIM) can present challenges for resources that don't fit neatly into CAISO's existing market model, market participants said during a regional conference last week.

Speakers at the Nov. 28 Regional Issues Forum discussed their approach to effectively integrating hydropower, coal and jointly owned plants into the market. The group, which includes representatives from 10 sectors that gather to discuss various EIM topics, can produce opinions and other documents for CAISO, the EIM Governing Body or the ISO Board of Governors.

Khai Le, senior vice president at generation supply management software developer PCI, told the forum that hydropower units are ideally suited to balance the variable output of renewables in the EIM, but could be much more effective with some operational changes to the market. Most EIM participants have a fairly rich mix of hydro and renewables, and "properly coordinated, that could be a very good marriage between

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EIM Governing Body Approves 'Consolidated' Initiatives

By Jason Fordney

BOISE, Idaho — Decision-makers for the Western Energy Imbalance Market (EIM) last week approved a set of market initiatives that represents a narrowed-down version of a package CAISO proposed to market participants earlier this year.

The EIM Governing Body on Nov. 29 unanimously approved CAISO's "consolidated EIM initiatives," which will automate some manual processes, facilitate bilateral settlements and improve the market's modeling accuracy.

CAISO Senior Adviser Don Tretheway briefed body members on the three aspects of the proposal over which they had decisional authority. In a presentation, he explained that one measure allows auto-matching of balancing changes in intertie schedules between an EIM resource and a non-EIM resource, allowing a member to use the external resource to "self-balance" an intertie change.

The initiative also automates the updating of mirror system resources at CAISO intertie scheduling points, which is done to prevent imbalances. Those resources allow the market to solve for the ISO and another EIM area at the same time.

"Currently, EIM entities are responsible for manually updating this mirror system resource," Trethaway said, noting that the manual process is subject to error or delays.

A third aspect of the approved initiative supports imbalance settlement of EIM base transfer schedule changes. That measure will facilitate bilateral scheduling between EIM entities, allowing settlement of energy transfers at agreed-upon financial locations for bilateral schedule changes occurring after base schedules are submitted.

In September, CAISO announced it was dropping several aspects of the consolidated EIM initiatives because of negative feedback from stakeholders. (See CAISO Drops Proposed EIM Changes.) One proposal would have allowed non-EIM third-party transmission owners to provide transfer capacity in the market, while another adjusted management of bilateral schedule changes. A third measure would have ensured payments to EIM entities that currently don't get compensation for wheeling power through their balancing areas.

Chairman Douglas Howe clarified with Tretheway that third-party transmission providers would reduce their own congestion revenue by providing the increased capacity to the EIM "and work against" their own interests.

"Is this really a feasible initiative at all?" Howe asked. Tretheway replied that it might be workable in certain cases with EIM transfers.

The disincentive was an issue raised by stakeholders during review of the proposal, leading it to be dropped from the initial package. (See *CAISO Drops EIM Third-Party Transmission Plan*.)

The Governing Body last week also gave advisory approval to separate rule clarifications for CAISO's non-generator resources (NGR) market enhancement, which allows new types of resources (such as storage) to participate in the ISO's regulation market. Powerex is using NGR to model its participation in the EIM, and the ISO said the changes provide additional clarity on market rules for NGR — including clarifying that such resources are subject to local market power mitigation and are not eligible to account for resource adequacy capacity.

"This is something that you would be doing irrespective of whether the EIM existed?" Howe asked, which Tretheway confirmed.

CAISO News

Hydro, Jointly Owned Coal Face EIM Challenges

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the two," Le said.

But hydro operators believe "there is lots of room for improvement in terms of hydro dispatch in the EIM market," he said.

EIM hydro operators include PacifiCorp, Pacific Gas and Electric, Portland General Electric, Puget Sound Energy and Southern California Edison. Their hydro resources vary, and include pumped storage and "cascading hydro" systems in which the discharge from one hydro plant is used as intake for another. Seattle City Light will be the first EIM participant to offer 100% hydro resources when it joins the market in April 2019.

Modeling hydro resources can also be more difficult than other types of generation, Le said. Hydro owners cannot model their plants using CAISO's "multi-stage generator" (MSG) model because some MSG parameters might only be updated one or two times a month, while hydro units have much more dynamic characteristics that require modeling on an hourly basis.

And while MSG allows for modelling of so-called "forbidden regions" — the different configurations, characteristics and overlapping regions that constrain the operations of many hydro resources — the CAISO system does not recognize cascading hydro and does not understand hydro topology and constraints, Le said.

Integrated properly, hydro operators will get more value in the EIM for the same output they had prior to joining the market, he said. Flexible capacity payments from the EIM are not sufficient for hydro operators to modify their operating rules for the market, he said, constituting just about 5% of the market's revenue, which is mostly energy payments.

"The greatest challenge in operating your hydro resources is somehow trying to use your bid parameters to reflect the real-life hydro constraint that you have," Le said.

Difficulties for Jointly Owned Units

Kelcey Brown | © RTO Insider

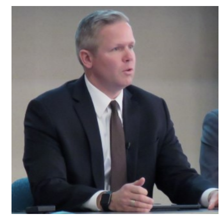
Operating jointly owned units in the EIM can also be a challenge, according to Kelcey Brown, PacifiCorp manager of market and analytics. When it first joined the market, PacifiCorp modeled the full output of its jointly owned Jim Bridger plant but ran into problems with modeling schedules, ramping, heat rates and other issues.

"There were a lot of problems, actually," she said. "We just could not get it right." So in February 2016, the company began modeling only its share of the plant, which has made the situation much smoother, she said.

CAISO does not have the ability to model one unit as separate, individual units, she said, creating the need for PacifiCorp to modify the model to show its individual share of each unit. The company is exploring participation with its Hunter 1 and 2 coal units, which would require a similar approach.

| © RTO Insider

Crossing the Rubicon



Clay MacArthur | © RTO Insider

Clay MacArthur, vice president of power marketing at Utah-based Deseret Power Electric Cooperative, met resistance from plant operators and others when he proposed joining the EIM, which the company finally did in August. Deseret's primary coal resource is the 500-MW Bonanza coal-fired plant, located in EIM member PacifiCorp's balancing authority area.

"There was a pitchfork-and-torches moment when I announced to the coal plant, 'Hey, I would like to take the plant into the EIM,'" MacArthur said. The company wanted to optimize its resource portfolio and improve reliability while gaining experience in organized markets.

"Everybody said 'You're insane, this is a huge mistake, you can't do this,'" MacArthur said, because of worries about engineering and responding to the market. The co-op had to be careful to model the Bonanza units for the EIM in a way that would not destroy the unit, he said.

Co-op members visited a PacifiCorp coal plant that was already participating in the EIM and explored what he called "tribal knowledge" about transitioning into the market, which helped convince the doubters.

The EIM does not require owners to completely turn over control of their plants, MacArthur said, but for Deseret, joining the market did involve plant upgrades, simplifying market modeling and using bidding strategies and operational expertise.

"We had to just kind of cross the Rubicon, and hope for the best."

ERCOT NEWS

ERCOT Stakeholders OK $246.7M in Freeport Reliability Projects

By Tom Kleckner

ERCOT stakeholders unanimously endorsed almost $250 million in transmission projects during last week's Technical Advisory Committee meeting, sending the package to the Board of Directors for its Dec. 12 meeting.

The two projects will address "significant" industrial growth in the Freeport area, a seaport south of Houston on the Gulf of Mexico. Newly committed industrial loads are expected to push the area past 2.2 GW by 2022, surpassing the heavily populated Rio Grande Valley.

The market "thinks about big meaty load pockets like the [Dallas-Fort Worth] area, Houston, San Antonio and Austin, but we haven't really thought about Freeport," said Jeff Billo, ERCOT's senior manager of transmission planning.

ERCOT staff project a 92% increase in the area's load by 2019, from 1,028 MW to 1,979 MW. An additional 300 MW is expected by the end of 2022.

CenterPoint Energy, which services the area, submitted the "Freeport Master Plan Project" to ERCOT's Regional Planning Group, proposing a two-phase approach to solve reliability criteria violations caused by the increased load. Staff's independent review agreed with the projects' needs, finding multiple reliability criteria violations in 2020 and 2022 cases.

The $32.3 million first phase, or "bridge-the-gap upgrades," focuses on near-term reliability needs. It consists of a 345-kV loop and a series of reactors, autotransformers and capacitor banks at a key substation.

Option #	Option 1	Option 2	Option 3	Option 4	Option 5
Description	STP-JC	HILLJE-JC	BAILEY-JC	PHR-JC	Only line upgrades
Extreme Event Contingency Limitation	Yes	No	No	Yes	Yes
Voltage Stability Transfer Limit (MW)	2240	2160	2080	1560	360
Dynamic Stability Criteria Violations?	Not studied	No	No	Not studied	Not studied
Projected Load for 2022 Criteria Violations?	No	No	No	No	No
Projected Load for 2022 + High Load Sensitivity	None	P6	P3/P6	Not studied	Not studied
New ROW Distance (miles)	50.4	62.4	48	60	0
Estimated Cost (Million)	$223.2	$272.5	$214.4	$220.0	$281.8

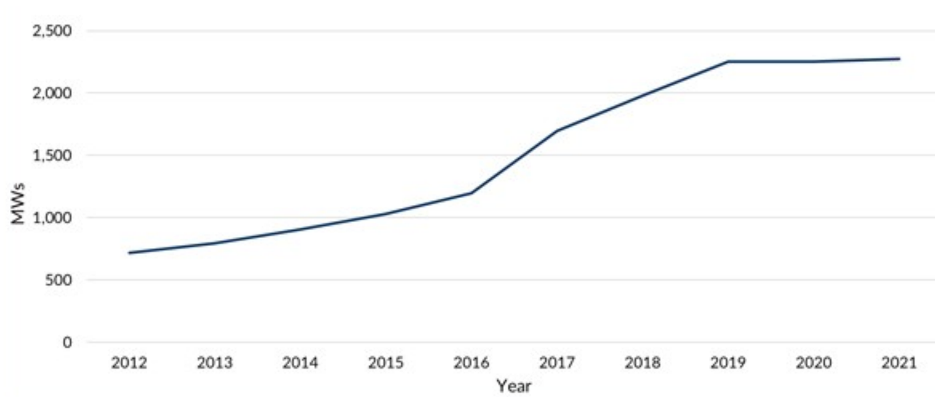
2022 project options — summary of results | *ERCOT*

The $214.4 million second phase comprises a new 48-mile, 345-kV double-circuit line and circuit upgrades to another 345-kV line. It was one of five options considered by staff, four of which involved a new 345-kV right of way, and would meet the "long-term reliability criteria needs in the most cost-effective manner."

The other four options had cost estimates of between $223.2 million and $281.8 million.

"We realize there is a long-term need to put in bigger infrastructure projects, but to get to that point, interim upgrades need to be done," Billo said. "More upgrades will need to be done in order to meet the long-term needs of the system."

Staff's recommendation met little resistance from members, who only needed to be assured the load increase will be included in ERCOT's next Capacity, Demand and Reserves (CDR) report. That report, to be released Dec. 18, includes a snapshot of planned resource additions during the next five years, current information about existing resources and the annually updated peak demand forecast for the next 10 years.



Freeport historic and projected load | *ERCOT*

Billo also updated members on the South Plains Project, a proposed $247.5 million, 345-kV line in the Texas Panhandle.

Billo said Sharyland Utilities has proposed the transmission line as an economic project but that ERCOT's analysis has yet been able to economically justify the project. He said about $210 million of the South Plains Project overlaps with work that would be done to integrate Lubbock Power & Light, which wants to shift 470 MW of load from SPP into ERCOT.

The Public Utility Commission of Texas has scheduled a hearing on LP&L's integration Jan. 17-18 (Docket 47576). Until then, staff has paused further analysis.

"We will wait to see what happens in that hearing and the subsequent decision that comes out of the PUC," Billo said. "That may supersede the need to analyze part of [the South Plains] project. If the commission says we're going to go ahead with Lubbock and those lines get approved, we don't have to do an economic justification for [the South Plains] lines anymore."

Billo said staff would update its assumptions and Sharyland's capital cost updates, and add plant retirements and other fresh data in a potential reassessment of the project that could be ready by mid-2018.

ERCOT NEWS

TAC Briefs

TAC 'Un-Tables,' Endorses NPRRs

ERCOT's Technical Advisory Committee endorsed two previously tabled nodal protocol revision requests (NPRRs) following lengthy discussions last week.

NPRR815 increases from 50% to 60% the limit on load resources providing responsive reserve service (RRS) and requires them to provide at least 1,150 MW of primary frequency response (PFR). Changing the constraint will allow additional resources to provide RRS at lower costs, the Protocol Revisions Subcommittee said.

Lower Colorado River Authority's John Dumas questioned claims the higher limit would realize about $3 million annually. He said the analysis overlooked the costs of paying combined cycle units to pick up the inertia responsibilities of coal plants that will be retiring early next year. (See *Vistra Energy to Close 2 More Coal Plants*.)

"We all know combined cycle units are not going to run unless the energy price supports them running," Dumas said. "If you need combined cycles to run, you're going to have to cover their cost to run, which is going to have a cost impact on the energy price. So, I'm a little skeptical of the cost savings [ERCOT] has touted.

"I'm more worried about the reliability impact," he added. "This is not the time to 'untable' this."

"Once again, we have the people that get fired for reliability saying they looked at it, they looked at 4,100 MW retiring, and they don't see a problem with it," said ReSolved Energy Consulting's Bob Wittmeyer. "The question I have for ERCOT is, if we implement this today and once it is implemented, how long would it take you to say, 'Uh oh, we need to back up and take 50% of generation again.' Is this a four-month process to reverse, or can you do it overnight?"

Dan Woodfin, ERCOT's senior director of system operations, reminded stakeholders that the NPRR approves methodology for determining the minimum ancillary service requirements that can be procured in the day-ahead market. The ISO's new reliability desk can issue reliability unit commitment instructions or resort to the supplemental ancillary service market should the ISO be short in the intraday.

"We can change [the minimum ancillary service requirement] on a daily basis, if need be," Woodfin said. "I realize that's not preferable, and that's why we try to cover 70% of the requirement in the ancillary services market."

Woodfin said staff tested its methodology by taking out the retired resources and found there were some instances in the shoulder months when it would have had to buy an additional 50 MW of ancillary services.

Citigroup Energy's Eric Goff was among the independent power marketers who opposed tabling the NPRR, saying, "We know ERCOT says it will save money. … We know ERCOT says it's not needed for reliability. It has expressed that without reservations or doubt. This should be a noncontroversial vote."

The Texas Industrial Energy Consumers (TIEC), which argued successfully for tabling the change in September, again pointed out that NPRR848, currently being debated in the Wholesale Market Subcommittee (WMS), would create separate pricing for load resources and PFR-capable resources providing RRS.

However, a roll call vote to keep the NPRR on the table was split down the middle, failing to gather a two-thirds majority. The ensuing vote to endorse the revision passed by a 78-22 margin.

Members also endorsed NPRR825, which had also been tabled in September to allow staff to rework its impact analysis. Staff said the revision, which requires ERCOT to issue a DC tie curtailment notice before curtailing the tie's load, would result in a "more efficient operation of the grid." It also addresses the ISO's concerns about declaring an emergency condition before curtailing DC tie load for any reason, rather than using an automated process, staff said.

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ERCOT NEWS

TAC Briefs

Continued from page 11

Staff estimate the NPRR's requirements will add $200,000-300,000 in development costs for a software tool it would build with or without the NPRR, Woodfin said. "We need a robust tool … not just for this NPRR, but for a multiple of things, including future NERC requirements."

ERCOT currently issues curtailment watches instead of notices, doing so 48 hours in advance of the day-ahead market. Woodfin said automating the process would be a better option.

"We set limits [before the day-ahead market] and update them every hour going forward, so it's sort of a rolling 48-hour limit," he said. "Things change during the course of the day. Lines trip, that sort of thing. We need a mechanism to [automate] that."

The motion passed despite opposition from the consumer segment, receiving eight no votes and two abstentions.

ERCOT Staff Preparing for New RMR Rules

ERCOT COO Cheryl Mele told the committee that staff are refining protocol revisions to incorporate the Texas Public Utility Commission's September order on reliability-must-run service rules. (See "Commission Approves RMR Rule Change," *Texas PUC Resistant to NextEra's Minority Interest in Oncor*.)

The order adjusts the suspension-of-operations notice requirements and complaint timeline, requiring written notification to ERCOT at least 90 days before a generating resource is mothballed on a seasonal basis. It also gives the ISO discretion to decline entering RMR service agreements based on the economic value of lost load and requires Board of Directors approval of staff recommendations regarding must-run-alternative (MRA) service. Capital expenditures made under the service agreements could be refunded by the resource owner if the resource participates in the energy or ancillary service markets.

"Effective Jan. 1, we'll have this new process going forward, despite not having all of the protocol changes defined," Mele said.

Scott Ends 10 Years as RMS Chair, Vice Chair

CenterPoint Energy's Kathy Scott received a standing ovation from her fellow members after delivering her last Retail Market Subcommittee report. Scott is cycling off the group's leadership after 10 years as either its chair or vice chair.

"It's a lot of work to lead a subcommittee," said Sharyland Utilities' B.J. Flowers. "We're very happy Kathy has stayed with it for that long."

TAC Approves 2 Changes to Ancillary Methodology

The committee endorsed staff's recommendations to make two changes to its 2018 ancillary service methodology for determining non-spinning reserve needs.

The committee approved including solar generation in net load calculations and forecasts, and adjusting for additional over-forecast uncertainty from projected increases in installed wind capacity.

Goff, who chairs the Qualified Scheduling Entity Managers Working Group, asked that the WMS and the Retail Operations Subcommittee be directed to evaluate the non-spin procurement methodology, reflecting conversations taking place within his group and the WMS.

"Our deployments of non-spin aren't closely correlated with the procurement of non-spin because we don't typically forecast for error," he said.

TAC Vice Chair Bob Helton, of Dynegy, reminded Goff that reviewing ancillary service methodology is a TAC goal for 2018.

Staff did not propose any changes for determining regulation service and responsive reserve quantities.

The TAC also unanimously approved four other NPRRs and a verifiable cost manual revision.

- NPRR834: Clarifies processes associated with ERCOT's repossession of congestion revenue rights following a payment breach or other default by a market participant. The change specifies data transparency requirements; documents the disposition of auction revenue funds above amounts owed to ERCOT; clarifies that the one-time auction bids must be positive; and allows the immediate transfer of CRR ownership to the winning bidder should an auction be necessary.
- NPRR839: Updates the protocols to clarify that, upon receiving meter data transactions from transmission or distribution service providers, ERCOT will forward the transactions to the designated competitive retailer.
- NPRR843: Addresses four reporting items in Section 3 of the Nodal Protocols (Management Activities) by:
  - Changing the short-term system adequacy reports' logic for more consistent treatment of resource status; adding language to provide clarity to the reports' end users;
  - Creating a new report that will show the portion of ancillary service (AS) offers at or above 50 times the fuel index price (FIP) when the market-clearing price for capacity of the service exceeds 50 times FIP;
  - Adding elements to the "48-hour highest price AS offer selected" report, including the highest-priced AS offer selected in a supplemental AS market (SASM); and
  - Creating a SASM disclosure report to provide transparency into AS offers and awards for any SASMs executed within an operating day.
- NPRR846: Allows previously committed emergency response service (ERS) resources to participate in must-run-alternative agreements and modifies the methodology for evaluating the performance during the first partial interval for ERS loads on the alternate baseline. The change also defines acceptable parameters for an ERS generator's self-serve capacity, sets the ERS test performance factor to significantly lower values and in some instances to zero for resources with three consecutive test failures in a 365-day period, along with additional administrative changes and clarifications to existing ERS protocol language.
- VCMRR019: Provides clarifications needed following the incorporation of NPRRs 485 and 617 by shortening the timeline for acceptance or rejection of approved verifiable costs from five to three business days.

— Tom Kleckner

ISO-NE NEWS

Mass. Prepares for EV Growth, Alternative Energy Portfolio Standard

By Michael Kuser

DOER officials from left to right: Arah Schuur, director of energy efficiency; Joanne Bissetta, Green Communities deputy director; Jillian DiMedio, assistant director of Leading by Example Office; Michael Judge, director of renewable and alternative energy; and Will Lauwers, director of emerging technology. | *© RTO Insider*

BOSTON — Massachusetts' $2,500 rebates are increasing electric vehicle sales, and state officials are preparing for the shift in demand now, the state's Department of Energy Resources said Thursday.

"We do have a goal for 300,000 electric vehicles to be registered in the state by 2025," DOER Director of Emerging Technology Will Lauwers said in a briefing to the Environmental Business Council of New England on Nov. 30. "Providing the charging infrastructure for that is crucial."

EV registrations have grown from 782 in July 2013 to 3,770 as of March 31, 2017, according to the state Department of Environmental Protection. In the same period, the number of gas-electric hybrids has increased more than five-fold, from 1,034 to 5,701. The state launched its rebate program, which covers both EVs and hybrids, in June 2014.

Although the alternative transportation sector includes biofuels and gas-electric hybrids efforts, electric vehicles and transportation electrification dominate the state's efforts, Lauwers said. The DEP's program to incentivize workplace charging stations exhausted its funding this year.

"Utilities have shown interest in helping to reduce the cost of entry to deploying EV charging, so they would help to cover more of the associated costs with new meters, new pads and new connections," Lauwers said. "Then there's the VW funding."

As penance for having rigged diesel emissions test results, Volkswagen is spending $2 billion to install more than 300 vehicle chargers in 15 metro areas, including Boston.

Resiliency, not Totality

Lauwers said Massachusetts is "a nation-leader" in its commitment to reducing greenhouse gases and fostering new renewable energy resources and has "made a lot of progress in the past 12 months" on energy efficiency, energy storage and demand reduction.

He cited the DOER's June announcement of $10 million in incentives for energy storage demonstration projects, a 200-MW storage deployment target and a $40 million initiative that awards grants to cities and towns to use clean energy technologies to mitigate the risks of power outages arising from severe weather. Award announcements on the storage incentives are expected by early 2018. (See *Massachusetts Underwhelms with 200-MWh Storage Target*.)

Michael Judge, the DOER's director of renewable and alternative energy, said storage is key for both grid stability and reducing emissions. Without storage "you end up keeping all these fossil fuel units going because they can't ramp that fast," Judge said.

In discussing resiliency studies that the department conducted on 12 state medical centers, Lauwer said resiliency doesn't mean 100% of normal power availability, just enough to run core functions. For example, a nursing home might lose its heat in a power outage just because it needs 9 V to run the pilot light.

Infrequently used back-up generators at hospitals often fail in the first few hours of running, so energy storage can make a big difference in such situations, he said in discussing the agency's analytical tools that help facility administrators understand what energy resiliency steps are economically viable for them. In addition, DOER will soon be clarifying how much energy storage utilities can own and how they will be compensated, Lauwers said.

Massachusetts is funding incentives to include energy storage in solar installations, as well as grants for peak demand reduction. Pairing energy storage with solar panels is meant to enhance grid resiliency by reducing the demand curves. Peak reduction grants cover a wide range of projects, from utilities improving the efficiency of substations, to municipalities working to reduce the energy consumption of big-box retail stores, to a thermal energy storage project on Nantucket that will delay the need for a new undersea transmission cable.

The state this year launched its Solar Massachusetts Renewable Target (SMART) program to provide incentives for "long-term sustainable … cost-effective solar development." The program provides adders based on location, and to projects that provide unique benefits, including community solar and energy storage.

Judge said the state's new Alternative Energy Portfolio Standard is the only one of its kind in the country. The final draft regulations, expected to be promulgated on Dec. 29, include combined heat and power, flywheel storage, renewable thermal, fuel cells and waste-to-energy thermal technologies. The regulations oblige all retail electric suppliers to acquire a certain percentage of their power from eligible technologies, starting at 4.25% in 2017 and increasing by 0.25% each year.

"Heating is behind the electric sector in decarbonizing and amounts to about 30% of GHG emissions," Judge said. "DOER incentives for renewable thermal energy and heat pumps are paying off, with nearly 500 MW of combined heat and power systems installed as of the end of October 2017."

Energy Efficiency Peaking?

Arah Schuur, DOER director of energy efficiency, said the state will deliver $8 million in efficiency benefits this year and that those savings will continue to grow.

"You put in a light bulb, you put in an efficient piece of technology and it lasts for five, seven, 11 or 20 years, and those benefits accrue as we add more to the portfolio,"

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ISO-NE NEWS

New England Grid Prepared for Winter Reliability

By Michael Kuser

ISO-NE forecasts sufficient resources to meet demand for electricity this winter and will implement special operating procedures to maintain reliability in the event of higher-than-projected demand, unforeseen generator outages or natural gas supply constraints that squeeze gas-fired power plants.

The RTO on Thursday issued its 2017/2018 winter outlook, which forecast peak demand under various scenarios:

- 21,197 MW at normal winter low temperatures of about 7 F; and
- 21,895 MW in extreme winter weather dropping to 2 F.

Resources with Forward Capacity Market (FCM) supply obligations total 30,999 MW; including resources without FCM obligations, capacity totals 32,521 MW.

Last winter's peak demand of 19,647 MW occurred on Dec. 15, 2016, between 5 and 6 p.m., while New England's all-time winter peak of 22,818 MW occurred on Jan. 15, 2004.

The report highlighted "a continuing concern" that "the region's natural gas delivery infrastructure has expanded only incrementally, while reliance on natural gas as the predominant fuel for both power generation and heating continues to grow."

ISO-NE said 4,000 MW of natural gas-fired generating capacity is at risk of not being able to get fuel when needed.

The RTO said the retirement of the 1,500-MW coal- and oil-fired Brayton Point power plant in Somerset, Mass., in May removed a facility with stored fuel that helped meet demand when natural gas plants were unavailable.

The grid operator is again running its Winter Reliability Program, which provides incentives for demand-side resources and generators that stock up on oil or contract for LNG. The program, which runs from Dec. 1, 2017, through Feb. 28, 2018, will be replaced by new capacity market performance incentive rules that go into effect June 1, 2018.

Total energy consumption and peak demand have been flat in New England in recent years because of increased energy-efficiency measures and behind-the-meter solar photovoltaic (PV) systems. Both the normal and extreme peak demand forecasts include the 1,832 MW in energy savings from EE acquired through the capacity market. While PV helps reduce energy consumption during sunny winter days, demand peaks in winter after the sun has set. By reducing demand on sunny days, PV can help preserve other fuels for use when demand is peaking.

Mass. Prepares for EV Growth

Continued from page 13

Schuur said.

Lighting savings comprise 83% of residential energy efficiency gains and 23% of overall savings. Although the state has nation-leading goals for both electric and natural gas, efficiency savings seem to be peaking, she said.

"That's because of the change in the lighting market and the change in federal lighting standards. So, screw-in light bulbs are nearing market saturation. There's natural uptake of LED lights. This [is a] great good news story overall for energy efficiency," Schuur said.

The limits to lighting's contribution to efficiency savings will "require a whole new way of thinking about energy efficiency," she said. The DOER is exploring new ways to achieve efficiency results, such as addressing demand through utility programs, looking at the residential contractor market and driving innovation.

MISO NEWS

Storage Task Force Defines Role, Seeks Plan

By Amanda Durish Cook

After two meetings, MISO's newly created Energy Storage Task Force has established its charter but not yet developed a plan of action for next year.

While the group spent much of its Nov. 28 meeting finalizing language for its mission statement, it also agreed to schedule an additional conference call in late December to create a 2018 work plan covering storage discussion topics.

During the meeting, stakeholders settled on a sparsely worded charter that stipulates the task force will "engage subject matter experts in the identification of potential issues or topics that are unique to integration of energy storage or challenge the ability to realize benefits of energy storage."

The group will also "identify and track issues specific to energy storage that are within the purview of MISO in any of its administrative or functional roles."

The final version of the mission statement implicitly respects state jurisdiction over storage assets, stakeholders said.

Task force Chair John Fernandes said stakeholders and states were understandably wary of turning over storage assets to MISO's control. "The 800-pound gorilla in the room is state jurisdiction. There is concern from the states that they don't want to turn over a piece of hardware, an asset over to MISO," he said.

Indianapolis Power and Light's Lin Franks noted that New York has mechanisms in place that allow storage assets to be subject to both state control and ISO regulation, enabling them to participate in wholesale and retail markets "almost simultaneously."

The charter will now head to the Steering Committee for approval at its Jan. 24 meeting.

A Question of Priorities

Task force leaders have asked stakeholders to help determine the group's key priorities before the December call. The group expects to also submit an issue prioritization to the Steering Committee, which assigns specific issues to other committees.

Task force members said the group could track storage issues in MISO committees to ensure they are being addressed in order of priority. Some stakeholders cautioned the group that it shouldn't tread on the Steering Committee's assignment authority.

Fernandes said the task force will next month take up general education on energy storage issues, identifying what MISO market rules already accommodate storage and reviewing FERC's Notice of Proposed Rulemaking on storage participation in wholesale markets.

Some stakeholders asked the task force to be mindful of the need to act quickly on storage issues.

"MISO has already indicated that it's going to model storage in transmission planning. At what point in the calendar is MISO going to start modeling these things?" asked Customized Energy Solutions' David Sapper. "It seems like the sooner the better."

In written comments to MISO, DTE Energy asked the task force to make storage modeling in MISO planning its top priority.

The Energy Storage Association asked the task force to avoid "unnecessary administrative burden" and assign issues as quickly as possible, suggesting that the most urgent

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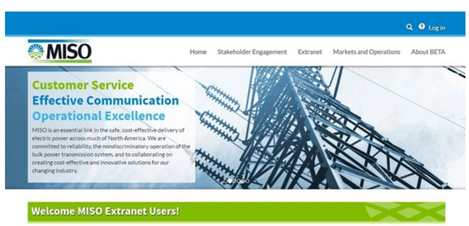
Winter Launch for MISO Website, Market System Project

By Amanda Durish Cook

MISO will roll out a new public website this winter and begin a $130 million project to replace its aging "monolithic" market platform with a new "modular" system.

The RTO is "off to a good start" to replacing the platform, Vice President of System Operations Todd Ramey said during a Nov. 28 conference call of the Board of Directors' Technology Committee. MISO expects to spend $21.7 million on the project in 2018, one-sixth of the amount budgeted over the next seven years. (See *MISO Makes Case for $130M Market Platform Upgrade*.)

Executive Director of Market Design Jeff Bladen said MISO will provide quarterly project briefings to both the board and stakeholders, with the first one slated for a meeting today of the board's Markets Committee. The RTO has already convened



Home page of the beta version of MISO's new website

the chief information officers of some of its member companies for a nonpublic meeting to discuss project risks and timelines.

MISO Director Baljit Dail asked that the RTO's next update identify key milestones in the platform replacement that could affect the overall project timeline if not met. MISO expects to begin migrating to the new system in 2020, keeping the current one in operation at least until 2021.

Bladen said MISO has met with the leaders of other RTOs that also use vendor General Electric to discuss how to ensure the company honors its delivery deadlines.

New Site Ready for Launch

MISO plans to launch its new external website next month, moving the current site to old.misoenergy.com, where it will remain available until early 2018 to ensure the RTO maintains its web presence if the new site fails.

"We'll keep both sites running concurrently, at least for the first few months, then make a decision on the old site in the first quarter of 2018," said Kacey George, MISO public relations specialist.

A beta version of MISO's new website has been up since October at beta.misoenergy.org.

MISO NEWS

Xcel Can Recover Costs if Minn. 345-kV Project is Canceled

By Amanda Durish Cook

Xcel Energy can recover its investment in a recently approved 345-kV line project in southern Minnesota if the project is abandoned for reasons beyond the company's control.

"We agree that the project faces certain regulatory, environmental and siting risks that are beyond the control of management and which could lead to abandonment of the project," FERC said in a ruling Friday (ER18-12).

Xcel put the incentive request to FERC on behalf of subsidiary Northern States Power, which will design and construct the $108 million Huntley-Wilmarth 345-kV line. The company will be able to recover all "prudently incurred costs" associated with its investment in the line. The abandoned plant incentive was effected Dec. 1.

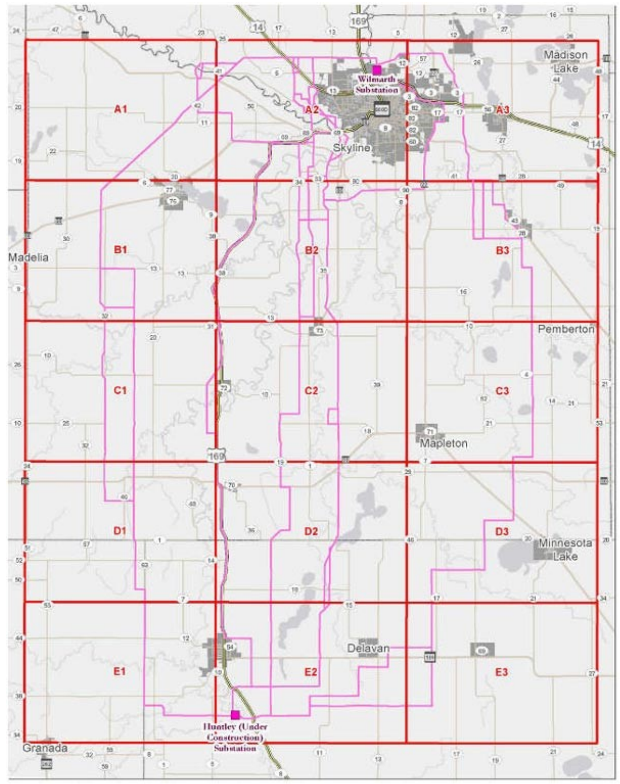
Northern States Power is investing $54 million with project partner ITC Midwest contributing the other half. Earlier Xcel estimates pegged project cost around $81 million. (See *MISO Board Approves MTEP 16's $2.7B in Tx Projects*.)

The line will connect Xcel's Wilmarth Substation and ITC Midwest's Huntley Substation in south central Minnesota near the Iowa border. The project, which is expected to be in service by the end of 2021, needs permitting approval from the Minnesota Public Utilities Commission.

FERC can consider the abandoned plant incentive if the transmission project "results from a fair and open regional planning process" or if a project "has received construction approval from an appropriate state commission or state siting authority."

The Huntley-Wilmarth project was part of the 2016 MISO Transmission Expansion Plan, though some stakeholders objected to the RTO's decision not to open the project up to competitive bidding. MTEP 16's only market efficiency project, it would have been put to a competitive process save for Minnesota's right of first refusal law. FERC cited the planning studies from MISO's annual MTEP process as grounds for approval.

"In this case, the MTEP transmission planning process, through which the project was approved, evaluated whether identified transmission projects will enhance reliability and/or reduce congestion," FERC said.



Preliminary route options for the Huntley-Wilmarth line in pink | *Xcel*

Storage Task Force Defines Role, Seeks Plan

Continued from page 15

issue is the development of resource adequacy rules and capacity accreditation for storage resources.

Indianapolis Power and Light suggested that stakeholders this month already begin focusing the discussion on storage participation in the interconnection process and energy and ancillary services markets, and send any readied issues to the Steering Committee. Entergy, however, asked for the first storage issue referrals by the end of the first quarter of 2018.

IPL also asked that MISO create a Gantt chart — a bar chart that illustrates project tasks and their start and end dates — to track storage discussions in the RTO's different stakeholder committees.

State of MISO Storage

MISO currently has one 1-MW battery that offers regulating reserves under a Stored Energy Resource designation, a market definition for short-term storage that was developed in 2008. However, an additional 50 MW of storage went through the interconnection queue in recent years, 20 MW of which is already in service, while the remaining 30 MW is expected to go live by the end of 2019, according to MISO spokesperson Mark Adrian Brown. The U.S. Department of Energy estimates that even more "distribution-connected energy storage is active or under construction in the MISO footprint," he said.

The RTO currently has 150 MW of storage in its interconnection queue.

MISO said that while its current rules do not expressly limit storage participation in regulating service, they do not "explicitly define a storage resource or product or fully clarify rules for how storage would integrate under other resource types." The RTO envisions creating a second type of Stored Energy Resource designation that would allow storage to be eligible to offer energy, capacity, up and down ramping, spinning reserve, supplemental reserve or regulating reserve "to the extent a particular storage resource is technically capable of providing any or all of these products."

MISO NEWS

Ruling Casts Doubt on Fate of Big Rivers Coal Plant

By Amanda Durish Cook

The prospects became bleaker for one Big Rivers Electric coal-fired generator last week after FERC declined to rehear an earlier ruling that denied a bid to extend interconnection rights for the Kentucky plant.

FERC earlier this year rejected Big Rivers' initial request to keep its Coleman Station interconnected to MISO's grid for another year after the RTO ended a three-year system support resource agreement for the 433-MW coal plant in September 2016. (See *FERC Refuses Interconnection Extension for Big Rivers' Plant*.)

In its rehearing request, Big Rivers did not challenge the commission's earlier refusal to extend the rights, but instead argued that a "termination of interconnection service for the Coleman Station could potentially harm reliability and impose increased costs on Big Rivers' members."

FERC disagreed with that contention (EL17-15-001).

"Big Rivers cites no specific evidence in support of its claim that there are potential adverse impacts on system reliability due to termination of interconnection service to the Coleman Station," the commission said in its Nov. 27 order. "Moreover, we note that MISO evaluated reliability concerns associated with the suspension of the Coleman Station when Big Rivers submitted its Attachment Y notice to suspend its operations."

The commission's ruling once again pointed out that Coleman cannot return to service until it complies with EPA's Mercury and Air Toxics Standards. It also noted the plant does not currently have load to serve since the nearby Century Aluminum smelter — once the plant's primary customer — completed load curtailment arrangements.

"Big Rivers itself acknowledges that the decision of whether and when to return the Coleman Station to service will be a complicated one. It thus appears that the Coleman Station may not be returned to service regardless of whether its interconnection service is reinstated," FERC said.

'Not Unique'

In early October, Rep. Brett Guthrie (R-Ky.) wrote to Chairman Neil Chatterjee urging a "full and fair consideration" of Big Rivers' request for rehearing.

But FERC said the challenges facing the nearly 50-year-old Coleman are commonplace: "While we appreciate the difficulties facing Big Rivers with regard to the future disposition of the Coleman Station, its circumstances are not unique. There are likely other generators that are currently uneconomic that would, if possible, reserve their interconnection service indefinitely in the hopes of future market changes."

> ***"While we appreciate the difficulties facing Big Rivers with regard to the future disposition of the Coleman Station, its circumstances are not unique."***
>
> **FERC**

Employees in front of the Coleman Station | *Big Rivers Electric Cooperative*

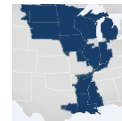
Big Rivers also argued that FERC was still allowing for disparate treatment of generators. While Coleman never had a generator interconnection agreement (GIA) with MISO, the RTO would be prohibited from cutting service to a generator operating under a GIA, the company contended.

FERC said the result would be the same, GIA or not, "because Big Rivers had not satisfied the requirement of taking 'significant steps to maintain or restore operational readiness … as soon as possible.'"

Big Rivers additionally filed a motion in September asking FERC to consider the "evolving status of MISO's policies on replacing retiring generation facilities and the interplay of MISO suspension, retirement and SSR rules." MISO officials and stakeholders are currently considering whether SSR units facing terminations should be able to maintain service even after contract expiration in order to allow them to participate in the RTO's annual capacity auction.

"Although styled as a motion to clarify the record, Big Rivers seeks to reopen the record and lodge the two MISO presentations for commission consideration," FERC responded. "Evidence that MISO and its stakeholders are in the process of considering changes to the Tariff that may allow generators to retain interconnection rights following retirement do not constitute a 'change in core circumstance' at 'the very heart of the case.'"

MISO NEWS



MISO Monitor Blames PJM for Market-to-Market Errors

By Amanda Durish Cook

CARMEL, Ind. — MISO's Independent Market Monitor said Wednesday that PJM has for years been committing two market-to-market operations errors that have possibly cost MISO millions of dollars.

Monitor David Patton contended that PJM has been "overstating" its response to transmission loading relief (TLR) requests and — more seriously — failing to order mandated tests required to define M2M constraints between the two RTOs.

As a result, PJM's neighboring balancing authorities have been forced to make up for the RTO's TLR shortfall and spend more on congestion, incurring costs they are not likely to recover.

PJM-MISO Joint and Common Market meeting on Nov. 29 | © *RTO Insider*

Neglected M2M Constraint Test

The test cited by Patton uses real-time system topology to measure the congestion generating resources in a non-monitoring RTO (in this case MISO) contribute to a PJM flowgate, and is mandated by the joint operating agreement between the two RTOs.

"This has not been instituted since it was introduced, which I don't know, is a decade or more," Patton said during a Nov. 29 Joint and Common Market meeting between MISO and PJM. "It was an error that was known and is a serious violation of the JOA."

PJM Director of Energy Market Operations Tim Horger said his RTO is still examining

Continued on page 26

MISO, PJM Pursue Pseudo-Tie Double-Charge Relief

By Amanda Durish Cook

CARMEL, Ind. — MISO and PJM expect to begin implementing a two-part remedy to their double-charging of congestion fees on pseudo-tied generation early next year.

MISO and PJM began collaborating to remove the overlapping congestion charges soon after the first complaint about the issue was filed with FERC last year. Stakeholders have lodged five complaints against the RTOs, including filings last year by Tilton Energy (EL16-108), American Municipal Power (EL17-29, EL17-37) and Northern Illinois Municipal Power Agency (EL17-31). Dynegy and Illinois Power Marketing filed jointly against MISO in March and added a motion to consolidate the previous complaints (EL17-54).

In an update to FERC on Nov. 22, the RTOs said their plan to address the complaints will ultimately treat pseudo-tie transactions like dynamically scheduled interchange transactions, in which two parties agree on a metered energy purchase and schedule it in both the day-ahead and real-time markets. The original value is first estimated then updated after delivery.

Tim Horger of PJM | © *RTO Insider*

The first stage of the plan — slated to be in place by March — adds market-to-market settlement and day-ahead coordination of pseudo-tie transactions to the RTOs' joint operating agreement. The second stage will have the RTOs alter their individual tariffs to address congestion charges, credits, rebates and hedges.

"There's been several challenges with the modeling on these ever since they've entered the market," PJM Director of Energy Market Operations Tim Horger said during a Nov. 29 Joint and Common Market meeting of the two RTOs.

The RTOs last month filed Tariff revisions (ER18-136, ER18-137) that would enable them to factor pseudo-tie firm flow entitlements into the day-ahead market, with the attaining balancing authority modeling the impact on flowgate capacity. In real-time M2M settlements, MISO and PJM will account for pseudo-tie market flows in payment formulas, so that charges between RTOs exclude the impacts of pseudo-tie resources on flowgates in the attaining balancing authority's calculations, ending the double-counting of congestion on flowgates.

Horger said the change comes down to modeling "proper limits in the day-ahead

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NYISO NEWS

NYISO Readies Market for Energy Storage, State Targets

By Michael Kuser

NYISO has developed a three-phase approach to opening its wholesale electricity market to storage resources, the ISO said Monday upon release of a comprehensive energy storage report describing the plan.

The plan will complement whatever energy storage target New York regulators set later this month for the state's electricity providers. Gov. Andrew Cuomo on Nov. 29 signed legislation requiring the Public Service Commission to establish targets by the end of the year. (See *NY Bill Sets Stage for Storage Targets*.)

The ISO report, "State of Storage: Energy Storage Resources in New York's Wholesale Markets," lays out three stages to facilitate storage participation — integration, optimization and aggregation with other distributed energy resources, NYISO Senior Vice President of Market Structures Rana Mukerji said Dec. 4.

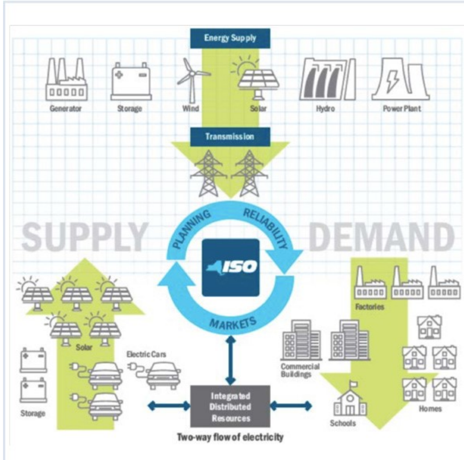
"The intermittent outputs of renewable solar and wind resources have to be balanced to provide reliable electricity to consumers," Mukerji said. "Storage resources will be increasingly important in this environment and help balance the intermittency of renewables and provide valuable grid services."

New York's electricity grid is in the midst of change driven by the state's Clean Energy Standard and Reforming the Energy Vision initiatives, designed to transition the state from an aging mix of gas and steam turbines to a greener and more distributed grid.

"We are trying to remove barriers for storage to enter into the market, and actual penetration levels for the various technologies will depend on other factors, such as the price of natural gas, the intermittency in the system — which drives price fluctuations, and also what level of incentives storage is getting from the state public policy initiatives," Mukerji said.

Grid Flexibility

Michael DeSocio, NYISO senior manager for market design, said the ISO is working on incorporating the latest technological



| NYISO

advances in storage, as well as developments in public policy, to allow the grid operator to take better advantage of the capabilities of storage resources.

"Energy storage is not a new concept, but advances in technology have brought energy storage within reach as a viable, competitive energy asset," DeSocio said. "These new storage technologies can offer the flexibility that quick-start gas turbines provide, while also helping absorb the excess energy that is produced from intermittent resources like solar and wind."

The ISO's new report distinguishes between storage in front of the meter and behind the meter (BTM), with the former more likely to participate in wholesale market transactions, although BTM storage could become a wholesale player when aggregated with other distributed resources. Storage developers and utilities in New York have been working with NYISO to establish dual participation of storage in retail and wholesale markets. (See *New York Sees Storage in Retail and Wholesale Markets*.)

"Today energy storage resources have to choose between providing only one or two ancillary services, and must be at least 1 MW in size," De Socio said. "NYISO's future energy storage model will allow storage resources to provide all of the grid services that they're capable of, while also reducing the minimum participation size from 1 MW to 0.1 MW, thereby increasing the facility for storage to be integrated into the grid."

Market-Ready by 2020

The ISO has kicked off the integration phase with stakeholders and "plans on having market rules ready for commercial use in 2020," which will complement the ISO's DER Roadmap issued in February, DeSocio said.

"A lot of the work that is already being contemplated in the DER program will inform this effort — things like how to aggregate resources — will be reused for integrating storage into the markets as well," DeSocio said. "So as we think about how to integrate smaller and smaller resources, leveraging a lot of that work has already been done."

DeSocio also addressed how the new market design will affect capacity bids.

"Today, storage resources that are participating in the wholesale markets must identify their desire to inject or withdraw electricity well in advance of the operating horizon," De Socio said. "Today, they have to tell us that roughly 75 minutes before that operating horizon."

The first phase envisions storage resources being able to provide a single offer indicating their willingness to inject or withdraw over the next hour. The markets could then help the resources group their utilization because market operators will have better information than is available 75 minutes before delivery, he said.

"That's the main improvement: allowing a single offer to be considered and letting the ISO select whether they should be withdrawing or injecting in any particular [interval]," DeSocio said.

As to how quickly storage will come online in 2020, DeSocio said, "We haven't particularly forecast the future of storage, but we are aware of storage resources today that are looking to participate, and we expect there will be more of them as they become more cost-effective and as policies evolve."

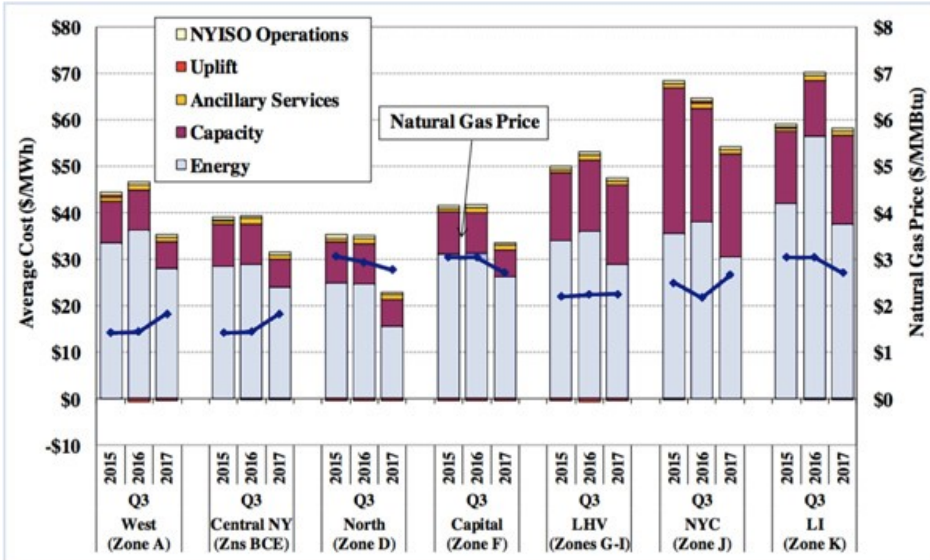
The ISO's new storage policies will not eliminate the need for peaking plants but complement them as storage provides a "more environmentally friendly" alternative, Mukerji said.

NYISO NEWS

NYISO Q3 Prices Fall on Lower Demand, Gas Costs

By Michael Kuser

NYISO third-quarter energy prices fell 16 to 30% compared with the same period a year ago because of mild summer conditions, lower natural gas prices and higher output from nuclear and hydropower plants, the ISO's Market Monitoring Unit reported last week.



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Reduced congestion into Long Island and increased congestion out of NYISO's North Zone contributed to the decline, as well as to "substantially lower" ancillary service prices and uplift costs, MMU Director Pallas LeeVanSchaick, of Potomac Economics, told the ISO's Market Issues Working Group on Nov. 29.

While the Q3 report showed that NYISO's market was competitive and that most prices and costs were down substantially compared with last year, the Monitor continued to identify potential improvements to market performance.

The report noted that a mild summer helped reduce loads by 1.8 GW on average, while natural gas prices in most of eastern New York and New England fell 12 to 19%. Nuclear and hydro units increased their average output by up to 640 MW.

Day-ahead congestion revenue fell 20% to $104 million partly because of the lower loads. West Zone lines accounted for the largest share of the congestion (25%) during the quarter, as imports from Ontario and hydro output met with bottlenecks while flowing east. New York City lines accounted for 20%, increasing because of higher gas prices relative to other regions and the expiration of the Con Ed-PSEG wheel. Long Island's share was down sharply to 17% because of fewer major transmission outages.

Flows from the North Zone accounted for 21% of congestion, as transmission outages and derates and hydroelectric output increased, leading to several extreme negative pricing events.

Actions used to manage 115-kV congestion in western and northern New York led to import limitations from Ontario and Quebec, as well as congestion on the higher-voltage system in other parts of the state. The MMU said the costs and reliability effects of this congestion could be reduced by modeling the 115-kV constraints in the day-ahead and real-time markets.

Capacity Market Spot Prices Down

Third-quarter spot prices for capacity ranged from $2.21/kW-month in Rest of State (ROS) to $9.97/kW-month in New York City. Average spot prices were down 18% in the city and 41% in ROS, but up 6% in the G-J Locality and 51% on Long Island. Demand curve revisions reflecting changes to assumptions about the unit net cost of new entry were a primary driver for the

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NYISO Reports Adequate Capacity for Winter

New York's electric system has the capacity to meet demand for electricity during extreme cold weather conditions through the 2017-2018 winter season, according to NYISO.

The ISO forecasts peak demand this winter of 24,365 MW, slightly higher than the 24,164-MW peak of last winter, when weather was milder than the 10-year and 20-year averages, Vice President of Operations Wes Yeomans said in a review of the ISO's 2017-2018 winter outlook Thursday.

New York set its record winter peak in 2014, during polar vortex conditions that pushed demand to 25,738 MW. If extreme weather produces colder conditions, with composite statewide temperatures in the 5 to 6 F range, peak demand across the state could increase to approximately 25,989 MW.

Total capacity resources, which include generation, imports and demand response, are expected to total 44,557 MW this winter, including 41,454 MW of generation, 2,311 MW in net external capacity purchases and 792 MW of DR. The ISO maintains 2,620 MW of operating reserves — generation resources above the amount needed to meet projected demand for electricity on any given day.

— Michael Kuser

NYISO NEWS

NYISO Q3 Prices Fall on Lower Demand, Gas Costs

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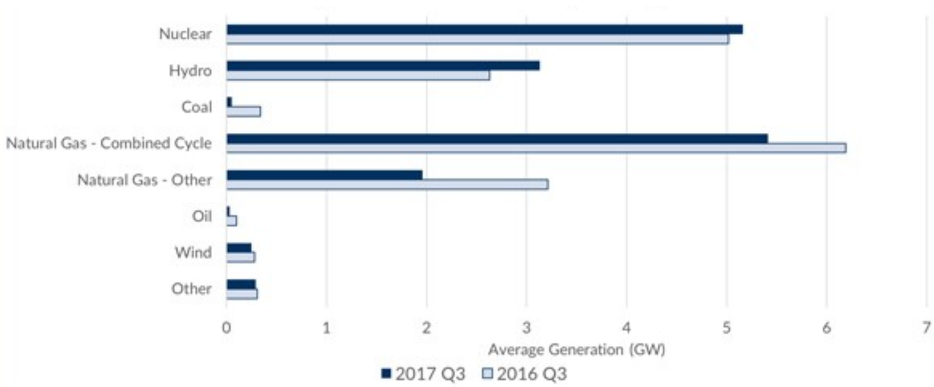
increased prices.

While an increase in installed capacity (ICAP) was a dominant factor in the ROS price rise, supply was up only modestly from a year ago, reflecting higher test values for dependable maximum net capability, the revival of the Greenridge 4 coal unit and new wind capacity upstate. Cleared import capacity rose 350 MW from a year ago, primarily from PJM. Import capacity from Ontario increased by an average of 105 MW, offset by a similar reduction from New England.

Reserve margin and locational capacity requirements rose in all regions as a result of a recent study by the New York State Reliability Council. However, peak load forecasts fell across all regions, neutralizing the price impact from higher installed reserve margins and locational requirements.



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Sharp Fall in Reserve Prices

The report also showed that day-ahead reserve prices fell by 28 to 44% from a year ago, consistent with lower load levels and lower locational-based marginal prices and primarily attributable to a decrease in reserve offer prices. After reserve market design changes in November 2015, the MMU observed offers above the standard competitive benchmark (i.e., estimated marginal cost), which it said is partly attributable to the difficulty in accurately estimating the marginal cost of providing operating reserves. However, day-ahead reserve offer prices have gradually fallen as suppliers gain more experience.

In the third quarter, a large number of units offering reserve capacity — particularly fast-start resources in eastern New York — further reduced their offer prices. The MMU said it continues to monitor day-ahead reserve offer patterns and consider potential rule changes, including whether to modify the existing $5/MWh "safe harbor" for reserve offers in the ISO's market power mitigation measures.

Congestion Management and Pricing

The MMU noted that the ISO's market-to-market phase angle regulator (PAR) coordination process expanded in May after the expiration of the 1,000-MW Con Ed-PSEG Wheel. (See NYISO Members OK End to ConEd-PSEG Wheel.) Congestion increased through Millwood and into New York City. In general, transmission lines in the A/B/C and J/K zones were operated more efficiently. However, the MMU observed that PARs in those areas were often not utilized to help manage congestion, being adjusted only one to five times per day on average.

The Monitor found that NYISO improved its transmission shortage pricing in June by modifying the second step of the graduated transmission demand curve (GTDC) from $2,350/MW to $1,175/MW, removing the feasibility screen and applying the GTDC to all constraints with a non-zero constraint reliability margin. As a result, constraint relaxation has been much less frequent, with violations occurring in 6% of interval during the third quarter, compared with 59% last year.

Average constraint shadow prices during transmission shortages fell moderately in most areas. Constraint relaxation leads to inefficient prices that are volatile and uncorrelated with the severity of congestion, the MMU said. Despite improved pricing outcomes, constraint shadow prices still did not properly reflect the importance of some transmission shortages. Accordingly, the MMU continues to recommend developing constraint-specific transmission demand curves.

FERC Grants NYISO RMR Compliance Extension

FERC last week approved NYISO's request for a 30-day extension for submitting additional reliability-must-run tariff revisions. The ISO must now file the changes no later than Jan. 16, 2018 (ER16-120).

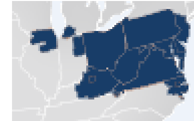
NYISO had appealed for more time to consider directives the commission set out in a Nov. 16 order, which largely accepted the ISO's RMR proposals but asked it to clarify that a developer could propose solutions to a reliability need that are not market-based and involve generators that are already mothballed or in a forced outage.

(See FERC Approves NYISO Reliability-Must-Run Plan.)

The ISO said the additional time would enable it to develop compliance revisions that fully address the directives and allow New York stakeholders an opportunity to review any changes and provide feedback. It also said the extension would help it avoid disputes with stakeholders and obtain input from its Independent Market Monitor.

— Michael Kuser

PJM News



PJM Demands Agreement on Tx Replacement Definitions

By Rory D. Sweeney

VALLEY FORGE, Pa. — After years of intractability, can PJM's Transmission Replacement Process Senior Task Force play nice? The RTO is hoping it can be forced to.

PJM's Fran Barrett, who administers the task force, told stakeholders at last week's meeting that transmission owners and customers must agree on a common definition of "end-of-life facilities" to move forward. He said that at its next meeting on Feb. 1, stakeholders will vote to approve a working definition that would apply only to discussions within the task force.

"We're going to put an end to the end-of-life discussion at the next meeting," he said.

The directive came after transmission owners declined to endorse a definition developed by Mark Ringhausen of Old Dominion Electric Cooperative. Stakeholders had debated the meaning of the term at previous meetings, and Ringhausen offered to develop a proposed definition.

The task force has made little progress since it was chartered in May 2016 to "develop alternatives for providing more transparency and consistency in the communication and review of end-of-life projects in the Regional Transmission Expansion Plan." FERC issued a show cause order in August 2016 questioning whether PJM TOs' procedures for planning supplemental projects provided stakeholders opportunity for "early and meaningful input and participation," as required by Order 890 (EL16-71). That precipitated a 10-month hiatus of the task force, which ended in July. (See *Softer Rhetoric as PJM Members Seek Replacement Rules Accord*.)

Supplemental projects are proposed by TOs to meet local needs, but they are not required by PJM's reliability, economic efficiency or operational performance criteria. Their costs are paid by the TO zone and are not regionally allocated, unlike baseline upgrades resulting from the RTEP.

The commission's show cause order directed the TOs to file rule revisions, or counter with evidence that they were already in compliance with Order 890, within 60 days. The TOs responded Oct. 25, contending that the PJM Operating Agreement already complies with the order, but also proposed a Tariff amendment, Attachment M-3, that they said would improve transparency. Attachment M-3 would add more specificity to annual stakeholder reviews of TOs' assumptions and methodology, along with TOs presentations of their views on local transmission needs and proposed solutions.

American Municipal Power's Ed Tatum (left) and ODEC's Mark Ringhausen | *© RTO Insider*

FERC, which was without a quorum between February and August, has not ruled on the filing despite promising it would act within about three months of the TOs' response.

Endorse or Propose

At last week's meeting, TOs were divided on Ringhausen's proposal. PPL's Frank "Chip" Richardson said it "helps define it for me as to what are we really talking about in this task force," but others hesitated to support it. Tonja Wicks of Duquesne Light said she had not received approval to endorse a definition and asked that the vote be deferred until her company could review it.

"This is a recommendation by one stakeholder of a definition, not the task force definition," she said.

"And what I'm asking the task force participants: Can you march under this flag for purposes of this discussion to say this is the end-of-life definition?" Barrett said.

"Duquesne is okay with this definition being an ODEC-represented definition," Wicks said. "We haven't agreed on any of terms in the definition."

"That doesn't help us very much," PJM's Steve Herling responded. "We're trying to have a set of boundaries for the conversation this group needs to have."

"We can use those words any way you define them, as long as we're not committing that we agree with those definitions," Exelon's Gary Guy said.

Barrett agreed to the deferral requested by Wicks but told stakeholders to come prepared to endorse the definition or propose an alternative.

"One thing that I do not want to get involved in is … trying to parse every component [at a transmission facility] to justify whether it falls within this definition," Herling warned. "If it has to be replaced, it has to be replaced."

Analysis Details

Earlier in the meeting, Ed Tatum of American Municipal Power asked PJM to detail its procedures for analyzing projects proposed by TOs.

"With regards to the baseline projects, the narrative is very clear as to what PJM is going to be looking at and thinking about," Tatum said. "With regard to projects that are not in [FERC] Form 715 and/or are not part of PJM's baseline — in other words end-of-life and/or supplemental projects — we do not have a narrative evaluation or assessment about how these things work."

"That actually seems like a fairly trivial thing to fix because the level of analysis that we do is the same, so we can memorialize that somewhere," Herling said, adding that the analysis is consistent with other studies PJM performs to determine whether retiring a facility will cause a reliability violation. "That's based on all the tests we do in the RTEP. ... I don't see [that] there's a documentation issue, but we can make it more clear if people are concerned."

Tatum continued, asking how certain Form 715 filing requirements are met for supplemental projects, which are submitted by TOs and aren't necessarily individually vetted by PJM.

"I don't think that the filing requirements are specific to each facility on the grid individually," Herling responded. "We don't try to demonstrate that every facility individually satisfies some criteria. We show the system is reliable and that we have done the

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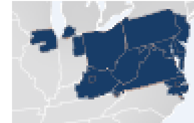

IMM Opposes PJM Stakeholder Bid for Frequency Response Payments

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM's Independent Market Monitor and the RTO are at odds over whether generators should receive additional compensation for providing FERC-mandated primary frequency response.

PJM led most of last week's meeting of the Primary Frequency Response Senior Task Force because, aside from the compensation issue, the Monitor's proposal is nearly identical to the RTO's. But that single issue attracted criticism from stakeholders. (See "Market-Based Frequency Response Solution Hard to ID," PJM Operating Committee Briefs: Nov. 7, 2017.)

The Market Monitor argued that compensation for primary frequency response, in terms of capacity costs, avoidable maintenance costs and any heat rate loss is already accounted for in PJM's existing capacity and energy markets. That position is "kind of a nonstarter from a generator side," American Electric Power's Brock Ondayko said. The payments are necessary because the revenue provided by PJM's capacity and energy auctions are "nowhere near the supporting levels for those types of resources," he said.

Howard Haas of Monitoring Analytics argued that all of the costs involved in providing primary frequency response are baked into the market already through the cost of new entry calculation and should be included in resources' capacity auction offers. PJM's interconnection agreement requires all new units to provide the service.

"There is an obligation to provide the service," Haas said. "To the extent that you're eligible to participate in the capacity market … you have the opportunity to recover associated capacity costs and any going-forward, avoidable costs. … The capacity market does not make a distinction between new and old units, and the CONE unit includes the capability to provide the service." (See FERC Has More Questions on Frequency Response NOPR.)

Providing primary frequency response isn't new to PJM, and any heat-rate losses can be accounted for in the 10% adder included with energy-market offers, he said.

Ondayko dismissed that, saying the only way to receive auction revenue is to offer well below the unit's costs.

Haas acknowledged that the natural gas boom "turned the market upside down" and that "the prices are low." But he said prices are low, in part, because "the market is long on supply" and uneconomic units should retire.

"You can get up to one-and-a-half times CONE if the market is short. It's not," he said.

"We really need stakeholder feedback on what they think the costs would be."

Glen Boyle, PJM

Tom Hyzinski of GT Power Group questioned Haas on competition from demand response, which doesn't provide the inertial benefits necessary for frequency response. Haas agreed that DR should be a demand-side product rather than supply and said more needs to be done to address speculative DR offers. However, load is not required to sign an interconnection agreement.

The Argument for Compensation

PJM's Glen Boyle said "there is a cost" to providing primary frequency response. "We want to offer a way to recover it similar to reactive supply," he said.

He envisioned a process similar to PJM's current payment for reactive power in which market participants make an informational filing with FERC, which directs the RTO on how much to compensate the filer. The requests would need to be newly incurred costs that are not included in the unit's variable operations and maintenance (VOM) calculations.

"We really need stakeholder feedback on what they think the costs would be," Boyle said.

Those determinations might get tricky. When one stakeholder calling into the meeting suggested there might be ongoing costs for maintaining the operational flexibility to increase or decrease output, PJM's Eric Hsia said those sounded like lost opportunity costs, which FERC likely wouldn't accept.

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PJM Demands Agreement on Tx Replacement Definitions

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appropriate analysis."

PJM agreed to review its documentation to address both of Tatum's concerns.

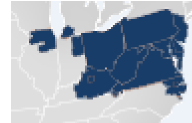
Design Component Changes

AMP also reviewed additional proposed revisions to the task force's design components. AMP's Lisa McAlister said the group felt it had "moved" substantially to include TO feedback.

Herling questioned some of the details AMP proposed.

"Some of that level of specificity, we're going to have to figure out does that actually make sense in the direction that we're trying to take the [Transmission Expansion Advisory Committee], which is to more dynamic communication, not focused on monthly meetings. Once we see what the proposals are and how they fit together, then we've got to figure out is that undoing some of what we're trying to accomplish with the TEAC."

Barrett asked that stakeholders begin reviewing the proposed language and formulate positions on what to include in a final supportable package.



No Solution for PJM Incremental Auctions

By Rory D. Sweeney

VALLEY FORGE, Pa. — It turns out overtime won't resolve this jump ball.

During a September meeting of PJM's Markets and Reliability Committee meeting, the RTO's Brian Chmielewski announced that, while no proposal from the Incremental Auction Senior Task Force (IASTF) received the more than 50% approval needed to be moved for endorsement to the MRC, poll results showing that a majority of stakeholders wanted a change indicated a "jump ball" — and that compromise might be possible.

The task force is considering structural changes to the Incremental Auction process to eliminate significant clearing price differences between a delivery year's capacity auction and its three subsequent IAs.

But at the IASTF's meeting last week, Chmielewski revealed similar results from a vote taken in November, despite two additional months of meetings and negotiation. PJM's proposal, known as Proposal A'', was seven votes short of receiving the support needed to move on to the MRC.

The result wasn't altogether unexpected, as Chmielewski's early hope for compromise quickly faded at subsequent meetings. (See *PJM Members Still Split on Incremental Auctions*.)

"I think we've kind of come full circle," he said.

He later confirmed that Proposal A'' would nonetheless be presented for a first read at the MRC meeting on Thursday.

While the overall results were similar, Chmielewski noted that there were less total votes the second time around. Exelon's Sharon Midgley wondered if holding the vote shortly before the Thanksgiving holiday accounted for the voter apathy.

"As a whole, the group has done a lot of compromising," she said.

The IASTF was also tasked with investigating concerns about market distortion stemming from market participants using replacement capacity to take advantage of the clearing price differences, but stakeholders decided to hold off on that issue until the MRC has decided on the Proposal A'' structural changes.

"I would certainly support putting the replacement discussion in abeyance until we see the outcome," said Carl Johnson, who represents the PJM Public Power Coalition.

"I'm happy to revisit that conversation once that path is clear," agreed NRG Energy's Neal Fitch.

Fitch also asked when stakeholders could expect the Independent Market Monitor's promised update of its report on replacement capacity. An IMM staff member said it would be published shortly.

With those concerns in mind, stakeholders agreed to cancel the task force's Dec. 18 meeting and instead reconvene at the next meeting scheduled for Jan. 19.

IMM Opposes PJM Stakeholder Bid for Frequency Response Payments

Continued from page 23

He said compensation would have to focus on operations and maintenance costs like those incurred for maintaining a heat rate. He said care would be taken to write the rule such that generators can't "double dip" on costs they've already recovered.

Carl Johnson, who represents the PJM Public Power Coalition, questioned the wisdom of having generators file at FERC. "We're going to struggle with just allowing anybody going in with anything they deem reasonable," Johnson said.

Stakeholders also debated whether traditional generators with large rotating masses that produce synchronous inertia provide different benefits than renewables with converter-based "synthetic" inertia and should be compensated differently.

Ondayko said such issues should be included in the primary frequency response discussion; otherwise the discussion would be "missing out" on the "mix of resources" necessary to provide grid-scale inertia, he said.

Other Factors

PJM's proposal would analyze primary frequency response performance by measuring the difference between the RTO's requested action during a frequency event and how the unit responds when called. Units would have to be online and providing energy, operating between their minimum and maximum real-power output, with available headroom or footroom and assigned Tier 1 or Tier 2 reserves. The analysis would include a pass-or-fail threshold.

"We would take into account the available headroom or footroom and the expected response would reflect that," said PJM's Danielle Croop, adding that the analysis wouldn't "nitpick" on small changes in performance.

Units that are providing frequency regulation wouldn't be assessed. Nuclear units would still be exempted, as would units that are going to be deactivated and units with technical limitations. Operators would need to submit exemption requests within six months of the rule going into effect.

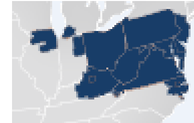
Stakeholders noted that some units can't set their deadband operation — which represents the upper and lower bands of acceptable operation — and that retrofits would be prohibitively expensive on units with exceptionally low capacity factors, particularly because they usually run when there are plenty of other units online to provide primary frequency response.

PJM's Vince Stefanowicz hesitated to agree, saying that during a restoration scenario where frequency regulation hasn't yet been established, "primary frequency response is kind of our first line of defense."

Johnson asked if there was a frequency event during the expectedly cold temperatures in the winter of 2014 often referred to as the polar vortex. Hsia said staff are looking into it.

The task force's next meeting is Dec. 20, when stakeholders will discuss implementation details, including concepts proposed by Dominion Energy.

PJM NEWS



MRC/MC Preview

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

RTO Insider will be at the Cira Centre in Philadelphia covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

Price Formation Problem Statement and Issue Charge

In addition to the voting items listed below, PJM will present a problem statement and issue charge on revising its price formation procedures. The initiative, which would seek ways to allow inflexible units to set LMPs, will be brought to a vote at the next MRC meeting, scheduled for Dec. 21. The RTO has scheduled four education sessions on the topic, which began on Dec. 4 with an explanation of the price formation status quo. The remaining sessions are scheduled for Dec. 11 and morning and afternoon sessions on Jan. 17. (See *PJM: Energy Price Formation Addresses DOE NOPR*.)

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

Members will be asked to endorse changes to Manual 11: Energy & Ancillary Services; Manual 18: PJM Capacity Market; Manual 27: Open Access Transmission Tariff Accounting; Manual 28: Operating Agreement Accounting; and Manual 29: Billing. The revisions implement PJM's transition to five-minute settlements under FERC Order 825.

3. DERs Update (9:30-9:45)

Members will be asked to endorse a proposed charter to convert stakeholders' work on distributed energy resources into a subcommittee reporting to the MRC. It includes a revision FirstEnergy offered on respecting relevant regulatory authorities. (See "Big Support for Jurisdiction Mention in DERS Charter," *PJM Market Implementation Committee Briefs: Nov. 8, 2017*.) The subcommittee was created because of concerns that previous DER discussions — which had been conducted in special sessions of the Market Implementation Committee — were hampered by an overly narrow problem statement and issue charge.

4. 2018 DASR Requirement (9:45-9:55)

Members will be asked to endorse proposed revisions to the 2018 day-ahead scheduling reserve requirement. (See "DASR Requirement Drops Again," *PJM Operating Committee Briefs: Oct. 10, 2017*.)

5. Credit Requirements for Regulation (9:55-10:05)

Members will be asked to endorse Tariff revisions to address a billing mismatch affecting credit requirements for regulation-only resources.

Regulation credits are accrued daily and billed monthly, while energy charges are accrued daily and billed weekly. Although the regulation-only resources' credits are much greater than the charges, the weekly bills for charges create a credit requirement, even though the much larger credit is due to the provider at the end of the month. The proposal would include daily regulation credits in weekly instead of monthly activity for calculating credit requirements. The change will apply to all resources, not just regulation-only resources.

6. FTR Credit Requirements for Transmission Upgrades (10:05-10:15)

Members will be asked to endorse proposed revisions allowing PJM to use modeling to improve its financial transmission rights credit requirements. FTR credit requirements for prevailing paths currently are based on weighted historical congestion on those paths, but transmission system upgrades can reduce congestion, decreasing the value of prevailing-flow FTRs.

The proposal would incorporate the PROMOD simulation results into the FTR credit calculator prior to the FTR bid window to incorporate consideration of major upgrades and reduce default exposure to PJM's members. (See "Give Them Some Credit," *PJM Market Implementation Committee Briefs: Oct. 11, 2017*.)

7. Price-Responsive Demand (10:15-10:30)

Members will be asked to endorse one of three proposals developed at the Demand Response Subcommittee to adapt price-responsive demand (PRD) to Capacity Performance rules.

PRD, which lets customers reduce their loads in response to energy prices in exchange for reduced capacity requirements, was developed before CP rules changed the requirements for demand response.

PJM says PRD bids should be available year-round, the same as generation resources under CP. But state regulators argue they should be allowed the option to make only seasonal contributions because PJM's summer peak loads exceed winter peaks by more than 20,000 MW.

The RTO's proposal and a similar one from Calpine would require PRD to reduce load in the winter like other CP resources. The status quo would relieve PRD resources from having to reduce winter loads. (See *PJM Grilled on Price-Responsive Demand Rule Changes*.)

Members Committee

Consent Agenda (1:20-1:25)

Members will be asked to endorse Operating Agreement revisions associated with PJM sharing of restoration planning generator data with transmission owners. (See "TOs to Receive Confidential Generation Data for System Restoration," *PJM Operating Committee Briefs: Sept. 12, 2017*.)

1. Elections (1:25-1:35)

Members will be asked to elect members of the Finance Committee, sector whips and the Members Committee vice chair for 2018.

2. Credit Requirements for Regulation (1:35-1:45)

Members will be asked to endorse Tariff revisions related to a proposed change in credit requirements for regulation resources. (See MRC Item 5 above.)

3. FTR Credit Requirements for Transmission Upgrades (1:45-1:55)

Members will be asked to endorse Tariff revisions to FTR credit requirements to reduce exposure posed by congestion changes resulting from major transmission upgrades. (See MRC Item 6 above.)

4. Price-Responsive Demand (1:55-2:15)

Members will be asked to endorse proposed Reliability Assurance Agreement revisions to address PRD. (See MRC Item 7 above.)

— Rory D. Sweeney

PJM NEWS

MISO Monitor Blames PJM for Market-to-Market Errors

Continued from page 18

the potential impacts of failing to request the tests but cautioned against labeling the failure to act a Tariff violation.

"PJM is not in a position to say that by not requesting the study it is in a Tariff violation," Horger said.

"That's a FERC determination," Patton agreed.

It would be "very difficult to quantify the impacts" of PJM's neglected tests, Patton said, but he thinks they explain some of the past gaps his monitoring firm has observed in M2M coordination. The Monitor's 2016 State of the Market report showed that substantial volumes of congestion were not coordinated because constraints were not properly identified as being M2M. From January 2016 to October 2017, Patton detected $341 million worth of congestion on constraints that should have been coordinated by PJM.

"Not all of this amount is due to this violation of the JOA; some are likely due to simply not testing constraints or not testing them in a timely manner," Patton said.

But in consistently failing to evaluate constraints affected by its neighbor's generators, PJM couldn't capture transmission outages, "frequently the cause of severe binding constraints," he said.

"Not only did this undermine efficient dispatch and congestion management, but [it] also effectively granted PJM an unlimited entitlement to MISO transmission" because it did not test for constraints causing congestion, Patton said.

He added that it would be impossible to eradicate all congestion from MISO and PJM's M2M coordination.

"We know that some of this uncoordinated congestion in MISO is because some constraints weren't requested to be identified. To be honest, we think that all issues that prevent a constraint from being quickly identified are problematic," Patton said.

PJM Miscalculation

Patton also contended that PJM's TLR calculation — which enables MISO, PJM and SPP to acknowledge and receive credit for relief provided during TLR procedures — has been incorrect since 2009. MISO first noticed PJM's error in September, when binding constraints during TLR procedures in the Tennessee Valley Authority area alone boosted MISO Midwest real-time monthly average prices by almost 8%, according to Patton.

"This has been very costly for MISO because MISO has incurred extreme costs attempting to provide the relief requested in response to a TLR," Patton said. "If it raised the relief obligation that MISO had, we're talking a lot of money."

MISO officials believe PJM has since corrected the problem, although they continue to investigate.

Patton and MISO seams management expert Ron Arness said no precedent exists for resettling energy prices because of TLR errors, but the Monitor thinks the impact could easily reach into the millions of dollars.

"In any particular month, the cost may not be big, but this has been happening for years," Patton said.

Horger pointed to the challenge of resettling prices influenced by TLRs.

"If after investigation, PJM decides that prices were affected, that doesn't change the fact that the dispatch reflected the generation movement [in response to TLRs]. That's a dangerous slope," he said.

MISO, PJM Pursue Pseudo-Tie Double-Charge Relief

Continued from page 18

market."

"PJM was modeling limits … that weren't reflective of what the congestion actually was," Horger said. MISO and PJM have been using a temporary rebate program until they're authorized to include pseudo-ties in the day-ahead scheduling process. (See *MISO, PJM Propose Solution to Pseudo-Tie Congestion Problem*.)

The RTOs hope to win FERC approval by March. "We're expecting some answers and solutions shortly," Horger said.

Phase 2

MISO and PJM will wait until later next year to roll out the second phase of the congestion remedy because it requires more complicated Tariff changes and complex software changes. Those revisions will require an attaining balancing authority to issue either refunds or financial transmission rights to cover the day-ahead congestions costs paid by pseudo-ties with load contracts. In the real-time market, credits and charges would be levied on pseudo-tie transactions based on deviations from their day-ahead schedules. The RTOs' would leave open the option for the native balancing authority to accept a pair of day-ahead virtual transactions for pseudo-tie transactions that have FTR hedges.

"It does require more extensive software changes because it involves a hedging mechanism for deviations between day-ahead and real-time. And it may also involve refunds," Horger said.

PJM is looking into developing a new product exclusively for pseudo-tie owners out of PJM that would allow them to hedge in the day-ahead market, similar to existing virtual transactions, he said. MISO, however, plans to hedge using its existing virtual transaction process because of the limited capability of its market system platform.

"If there's an under-collection or over-collection in the MISO market, it's going to be trued up with this market flow credit," Horger said.

The RTOs will have separate filing and implementation dates for the second stage of the plan, Horger said, with PJM planning to go live in June, with MISO lagging by a few months because of IT-related challenges.

"We're in the process of implementing a new settlement system, so that's going to impede our ability to deliver phase two," said Kevin Vannoy, MISO director of forward operations planning.

Some stakeholders asked if the disparate implementation dates were even possible.

Vannoy said the solutions boil down to Tariff changes that can be made independently. He promised more details on the second phase of the plan in early 2018.

Some MISO stakeholders are hoping the RTO will file a similar plan with SPP, where the potential for double congestion charges also exists, although the RTOs exchange far fewer pseudo-tied megawatts.

"We're hoping that the pseudo-tie congestion changes will apply to SPP as well," said Market Subcommittee Vice Chair Megan Wisersky, reporting on activities of MISO's Seams Management Working Group in October.

MISO Monitor not Pleased

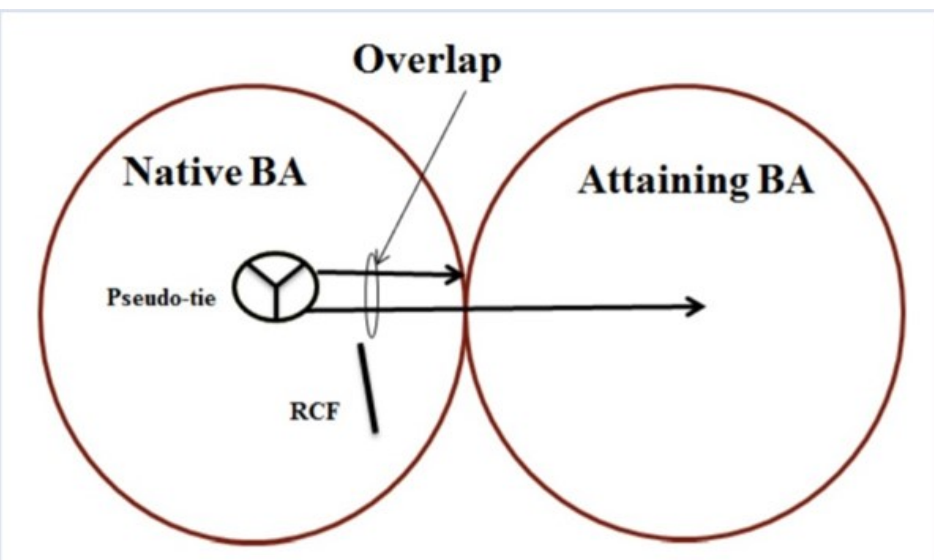
But MISO Independent Market Monitor David Patton said that MISO and PJM have yet to make a filing that will solve the underlying congestion and dispatch issues caused by pseudo-ties.

Patton's firm, Potomac Economics, filed a protest against the first phase of the overlap solution, saying nothing in the filings "ameliorates the myriad of significant problems" caused by the uptick in resources pseudo-tying from MISO to PJM. The Monitor also argued that FERC could not even fairly evaluate the RTOs' filing without also evaluating at least 10 other FERC dockets containing complaints against the their pseudo-tie process.

"We hope that FERC will respond to our complaint and bring some rationality to this process," Patton said at an Oct. 12 Market Subcommittee meeting.

Horger said that for pseudo-ties to function, PJM and MISO must have comparable treatment for external and internal capacity, a binding *pro forma* agreement and a solution to the RTOs' double counting of congestion.

"We need to make sure these pseudo-tie external resources are being modeled under the same criteria," Horger said.



| MISO

SPP NEWS

Court Rejects Challenge to SPP-Integrated System Merger

By Tom Kleckner

The D.C. Circuit Court of Appeals last week denied Kansas regulators' challenge to a 2014 FERC order approving SPP's merger with the Integrated System (IS) (15-1447).

In its petition for review, the Kansas Corporation Commission contended that FERC's approval of the merger allowed SPP to integrate Basin Electric Power Cooperative and Heartland Consumers Power District into its transmission footprint under agreements that shielded the two new members from paying certain transmission facility costs (ER14-2850, ER14-2851).

The Kansas commission argued that FERC "wrongly accepted a rate structure that disadvantaged the SPP participants" and "unreasonably accepted" what it called faulty data in the RTO's calculation of the merger's benefits.

At issue was the allocation of costs for SPP legacy facilities in the agreement between the RTO and the Integrated System parties. The KCC said FERC's approval would establish inequitable precedent that entities desiring to join an RTO can negotiate "sweetheart deals" in exchange for reducing administrative rates.

In an opinion authored by Senior Judge Stephen F. Williams, the court rejected the KCC's request to review FERC's decision, saying the court found no basis for a claim of undue discrimination.

"Kansas argues, in effect, that by accepting these provisions, SPP got taken for a ride," Williams wrote, pointing to a KCC expert's calculations that SPP would have received almost $360.5 million in revenue (net present value) over 10 years were the Integrated System parties required to pay for the use of its legacy facilities. The system comprises its own transmission zone within SPP's footprint, which is divided into 18 different zones.

While a Brattle Group study of the merger estimated the RTO would reap $220 million in benefits over 10 years, the KCC said the foregone revenue meant the integration will actually cost existing SPP members almost $141 million during that period.

The court noted FERC's determination reflected "prior investment decisions and the fact that existing facilities were built principally to support load within the [pre-merger SPP] sub-region," and said the commission's approval of similar arrangements "has withstood judicial review in analogous circumstances."

"FERC accurately described the agreement as reciprocal," Williams wrote. "It would be difficult to label it otherwise, as the agreement and FERC's approval assigned each side's legacy costs to the power consumers in that side." He said the arrangement's reciprocity undermined the KCC's contention that SPP left $475 million (nominal) lying on the table.

"Kansas never suggests any reason to believe that the IS parties would have agreed to share SPP members' legacy costs without demanding that SPP members share the IS parties' legacy costs," Williams wrote.

The court also said the KCC overlooked other benefits to the merger, such as increased efficiency and reliability; improvement in SPP's dispatch of power on its western edge; and a lower price of energy by virtue of reduced generation curtailment.

Williams said the Kansas regulators' claim of lack of access to the Brattle study was "somewhat exaggerated." The commission had access to a redacted, electronic version before the start of the FERC proceedings and other public data, he said, but it never pinpointed either a special reason to question the study "or some debilitating feature of the redaction."

The KCC also asserted its expert's testimony was "simply ignored" by FERC in disputing the proposed integration and SPP's cost/benefit analysis.

"Not true," Williams wrote. "As the … discussion demonstrates, the testimony was considered, but rejected on the merits."

The court also found no fault in FERC's decision not to order a hearing on the issue, noting the Kansas regulator was unable to point to any vulnerability in SPP's expert witness testimony that could have been "better resolved" with cross-examination rather than the analysis of written testimony.

"We therefore find no abuse of FERC's discretion," Williams wrote.

A KCC spokesperson said the commission is still reviewing its options.

SPP NEWS

FERC Orders Hearing in SWEPCO Rate Dispute

By Tom Kleckner

FERC last week ordered settlement judge procedures for a dispute involving an American Electric Power subsidiary's transmission rates (EL17-85).

In August, East Texas Electric Cooperative (ETEC) and Northeast Texas Electric Cooperative (NTEC) filed a joint complaint asking the commission to reduce Southwestern Electric Power Co.'s (SWEPCO) current base return on equity from 11.1% to 8.41% — a 269-basis-point reduction. In granting the co-ops' request for a hearing on the issue, the commission set a refund effective date of Aug. 31, 2017.

ETEC and NTEC buy power from SWEPCO under a revised supply agreement among the three parties, while NTEC and SWEPCO also have a separate agreement. The 11.1% base ROE in the contracts originated in a formula rate settlement filed by SWEPCO in 2001 for the NTEC contract, and the utility carried over that rate when it filed the ETEC-NTEC agreement in 2009.

The co-ops now contend that capital costs for electric utilities have declined significantly since the ROE was set in the initial agreement. As a result, their ratepayers are overcompensating SWEPCO by $2.43 million annually.

ETEC and NTEC filed testimony from independent consultant J. Bertram Solomon, who argued the 11.1% ROE rested on the commission's previous one-stage discounted cash flow (DCF) methodology and outdated assumptions about utility debt costs. Updated financial data and the two-step DCF method adopted by FERC in 2015 produced a zone of reasonableness of 6.42 to 10.62% and a median of 8.41%, Solomon's analysis showed.

SWEPCO asked the commission to dismiss the co-ops' complaint, saying the 8.41% ROE falls 216 and 191 basis points below the ROEs the commission approved in previous cases involving ISO-NE and MISO, respectively. The utility requested FERC delay any proposed refund effective date by five months, if it set the complaint for hearing.

The commission said it found the co-ops' DCF analysis to be "adequate" in establishing a sufficient case that SWEPCO's cost of equity "may have declined significantly below the level of its existing 11.1% base ROE." FERC said it was unpersuaded by SWEPCO's arguments against the zone of reasonableness, and it rejected the utility's request to delay refunds.

"We find no merit in [SWEPCO's] assertions that the commission should delay any appropriate relief to [its] customers," FERC said, "and we expressly decline to do."

The commission said that barring a settlement agreement, it expects to issue a decision by Sept. 30, 2019.

ETEC separately filed complaints against SWEPCO and three other AEP subsidiaries in June, arguing the companies' base ROE in SPP's AEP West pricing zone should be reduced from 10.7% to 8.36%. FERC earlier this month established hearing and settlement judge procedures in that case (EL17-76). (See *AEP Base ROE Complaints Ordered to Settlement*.)

No Unanimity in 'Coal Country' Hearing on CPP Repeal

| EPA

Last week's public hearings on the repeal of the Clean Power Plan provided EPA Administrator Scott Pruitt the stage he sought for coal industry supporters to blast the Obama administration's environmental policies. But not everyone stuck to the script.

Pruitt said he chose to have the hearings in "the heart of coal country to hear from those most impacted" by the CPP. During two days of hearings at the West Virginia State Capitol in Charlestown, coal magnate Robert Murray, West Virginia Attorney General Patrick Morrisey and other CPP critics derided the regulation as two dozen miners in hard hats and overalls looked on in support.

But the hearings also attracted many supporters of the CPP, as well as business groups who argued for replacing the CPP with less stringent rules to provide regulatory certainty and protection against litigation.

Pruitt announced the repeal of the CPP in October, saying the Obama administration overstepped its authority by regulating beyond the "fence line" of individual generators. The question facing the Trump administration now is what the replacement — required by EPA's 2009 finding that CO_2 emissions endanger public health — should be. (See *EPA to Announce Clean Power Plan Repeal*.)

Morrisey said the CPP "would impose a top-down reordering of state energy economies ... and would be disastrous for West Virginia and the country as a whole."

Murray, CEO of Murray Energy, said EPA should repeal the power plan "in its entirety," including overturning the endangerment finding.

But utilities and business groups urged EPA to leave the endangerment finding in place and focus on a replacement for the CPP.

The U.S. Chamber of Commerce asked for "durable and achievable standards."

Scott Segal, director of the Electric Reliability Coordinating Council, which represents utilities including Duke Energy and Ameren, said he supports a regulation that would require efficiency improvements in fossil fuel plants.

"While ERCC believes that absent specific guidance in legislation from the U.S. Congress, market principles are the most sound basis upon which to proceed, we nevertheless support the process advanced by EPA," Segal said. "Federal guidance of sufficient flexibility, and limited to actions within the fence line, can provide regulatory certainty, diminish frivolous litigation, and can aid in planning."

Richard Revesz, director of the Institute for Policy Integrity at the New York University School of Law, told the *Los Angeles Times* that repeal without replacement "could open the floodgates for litigation," leaving power companies vulnerable to "significant and highly uncertain liabilities."

"The EPA is required to publicly regulate these pollutants. Therefore, repealing the [CPP] without a replacement is illegal," Connecticut Department of Energy and Environmental Protection Commissioner Robert Klee testified. "Ignoring these facts won't make the problem go away; it will only serve to make it worse and delay the solutions we desperately need to meet this local, regional, national and international challenge."

Klee told *RTO Insider* later that while the first day of the hearing was dominated by many coal miners in the audience, EPA's strategy to hold the meetings in coal country "backfired" on the second day when dozens of ordinary West Virginians spoke out against repeal. Klee and others called for additional hearings in other regions of the U.S.

Coal miners outside the West Virginia State Capitol
| *West Virginia Coal Association*

The Obama EPA held public hearings in four states before issuing the CPP. An EPA official said last week that the agency was considering whether to hold additional hearings and had not set a schedule for announcing what kind of replacement rule it will propose.

"As a West Virginian, I'm insulted at the choice of this location," resident David Lillard said. "It doesn't make for great TV to have coal executives and some coal barons speaking about saving a few pennies per ton of coal, but it's great theater to have desperate coal miners carrying the message for the coal barons and the coal companies that have lied to them repeatedly. They were told their pensions were safe, and that was a lie. They were told they would always have health care; that promise was broken."

Nick Mullins, a fifth-generation coal miner from Kentucky, said the CPP will lead to safer and better job options for his son. "I don't want him to be a sixth-generation coal miner," Mullins said, citing the physical toll of the work.

"As long as I can draw a breath, I'm going to keep working to fight climate change and protect the land and country I love," said Stanley Sturgill, a Kentucky resident who said he suffers from black lung disease after more than 40 years as a coal miner.

"The coal miners I talk to seem to know coal jobs will continue to dry up, with or without a Clean Power Plan," said Angie Rosser, executive director of the West Virginia

Continued on page 31

Market Monitors Bring FTR Complaints to Congress

By Michael Brooks

WASHINGTON — The Market Monitors for CAISO and PJM told a House subcommittee Wednesday that their respective financial transmission rights markets are significantly flawed and need fixing, although they stopped short of asking for congressional action.

Appearing before the House Energy Subcommittee, Eric Hildebrandt, director of CAISO's Department of Market Monitoring, said electricity ratepayers in RTOs/ISOs nationwide are not receiving the full amount of congestion revenues as intended, losing more than $400 million a year instead.

After allocating an initial round of FTRs to load-serving entities that use the instruments as a hedge, RTOs auction off additional FTRs to third parties, typically sophisticated financial entities seeking to speculate on the potential to collect high rents from congested transmission segments.

"Unfortunately, revenues that ISOs collect from auctioned FTRs are consistently much lower than what the ISOs pay out to entities purchasing these FTRs," Hildebrandt said. "This makes FTRs highly profitable for financial entities, but these profits directly reduce the congestion revenues that would otherwise be refunded back to transmission ratepayers." He said that ratepayers only receive 52 cents in auction revenues for every dollar an RTO/ISO pays out to FTR holders, representing a nearly 100% profit for buyers.

Hildebrandt repeated his call for grid operators to end FTR auctions, a proposal he first made in CAISO a year ago. (See CAISO Monitor Proposes End to Revenue Rights Auction.)

In written testimony, PJM Independent Market Monitor Joe Bowring explained his RTO's auction revenue rights construct before echoing Hildebrandt's criticism.

"The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues," Bowring said. "The goal of the ARR/FTR design should be to return 100% of the congestion revenues to the load. But the actual results fall well short of that goal."

Opposing Hildebrandt at the hearing was TPC Energy CEO Noha Sidhom, appearing on behalf of the Power Trading Institute.

"The problem [in CAISO] is not with the FTR product; the problem is with the market design," Sidhom said. "They've got significant modeling issues. … There's something wrong with their pricing model. Also their outage scheduling is a real problem."

Sidhom said that more than 50% of network outages are not identified in time to be modeled in the ISO's FTR auctions. These problems result in inadequate revenues to ratepayers, but "you absolutely need the auction, because the auction is how you actually price the allocated rights."

"It's absolutely incorrect that the allocated FTRs are priced based on the auction," Hildebrandt responded. "They're allocated out, load-serving entities hold them and they get paid the congestion revenues."

Those who purchase FTRs through the auctions pay nearly half the price, and "the payout directly reduces the pot of congestion revenues that otherwise get fully refunded back to transmission ratepayers," he said

He also disputed that the problem was unique to CAISO, saying it exists in every RTO/ISO in the U.S., although he admitted it is more severe in California. In his letter to the subcommittee, Bowring said that PJM ratepayers have missed out on more than $1.7 billion in congestion revenues over the last seven planning cycles.

The hearing was the latest in the subcommittee's "Powering America" series, which has included discussions on reliability in the wake of a severe hurricane season, consumer advocates in energy markets and the Public Utility Regulatory Policies Act. Several congressmembers at the hearing admitted they were unfamiliar with FTRs and other virtual transactions, asking for basic explanations of their role in electricity markets.

The panelists also included Red Wolf Energy Trading CEO Wesley Allen, PJM General Counsel Vince Duane, former FERC General Counsel Max Minzer and Chris Moser, senior vice president of operations with NRG Energy.

Rep. Bobby Rush (D-Ill.), ranking member of the House Energy Subcommittee, questions the panel. | *© RTO Insider*

No Unanimity in 'Coal Country' Hearing on CPP Repeal

Continued from page 30

Rivers Coalition. "We've been pitted against each other by being told we'll either have coal, or we'll have nothing. This administration seems to thrive on public anger and conflict. It's a distraction. When people are fighting, they are not talking. … The clock is ticking to do something different than leaning on a dying industry."

Indeed, just last week PPL said its Kentucky utilities will retire their aging coal units and replace them with natural gas and renewables — even without carbon regulations. The company said it projects CO_2 reductions of 45 to 90% by 2050.

More: *Fairmont Times; Charleston Gazette-Mail; The Washington Post; Los Angeles Times; Washington Examiner; The Associated Press*

— Michael Kuser and Rich Heidorn Jr.

COMPANY BRIEFS

In Chapter 11, Suniva Talking to Potential Buyers

Suniva has been in contact with several entities interested in purchasing either it or its equipment, according to interviews and documents filed as part of its Chapter 11 bankruptcy.

Suniva is one of the solar-panel manufacturers that initiated the trade case that has President Trump considering imposing tariffs on imported solar products.

A sale of the company may influence the president's decision on imposing tariffs, said Lewis Leibowitz, a D.C.-based trade and customs lawyer.

More: Bloomberg Markets

Google Signs Wind PPA, Making it 100% Renewable

The Grand River Dam Authority said Google has agreed to buy 140 MW of power from the Red Dirt Wind Farm, a 300-MW facility located in Oklahoma's Kingfisher and Logan counties.

Constructed by Enel Green Power North America, the wind farm will be operational in early 2018 and will bring GRDA's total wind generation capacity to approximately 385 MW.

Google said the agreement with GRDA and other agreements it has recently signed have made it the world's largest corporate purchaser of energy and enables it to get 100% of its power from renewable sources.

More: The Claremore Daily Progress; 9to5Google

Indiana Michigan Power Upgrading Michigan Line

American Electric Power's Indiana Michigan Power subsidiary plans to upgrade a 69-kV electric transmission line in La Porte County and Berrien County, Mich.

The New Buffalo Area Improvements Project includes rebuilding approximately 7 miles of transmission line and upgrading area substations.

Some sections of the line will be rebuilt in the current right of way and may require updating or supplementing existing easements. For other sections, I&M is considering reroutes that would require new easements.

More: The Michigan City News-Dispatch

Toyota Building Fuel Cell Plant, Hydrogen Fueling Station

Toyota said Thursday it will build a renewable fuel-cell power plant and a hydrogen fueling station to support its operations at the Port of Long Beach in California.

The automobile manufacturer said the Tri-Gen system will generate 2.35 MW of power and 1.2 tons of hydrogen a day. Toyota expects the system to begin operations in 2020.

More: Bloomberg

Avangrid to Build Wind Farms To Supply Power to Google

Avangrid Renewables said Thursday that Google has agreed to purchase all the power from two wind farms with a total output of 196 MW it is building in South Dakota.

The Coyote Ridge and Tatanka Ridge Wind Farms will be located in Brookings and Deuel counties, just northeast of Brookings and east of I-29.

Avangrid is finalizing development work at the wind farms' sites and expects have both fully under construction by 2019.

More: Avangrid Renewables US

GlassPoint Solar to Build Massive Array for Oil Field

GlassPoint Solar will build an 850-MW array to create the steam needed to get oil from Aera Energy's Belridge Oil Field near Bakersfield, Calif.

The solar array will replace the 4.87 Bcf of natural gas used per year to obtain the oil, thus avoiding the emission of 376,000 tons of carbon.

GlassPoint also will build a 26.5-MW solar photovoltaic installation to help power the oil field's operations.

More: The Washington Post

WEC Energy Closing Pleasant Prairie Coal Plant

Pleasant Prairie Power Plant | *We Energies*

WEC Energy Group said last week it will close its coal-fired power plant in Pleasant Prairie, Wisc., in the second quarter of next year.

Wisconsin Industrial Energy Group and the Citizens' Utility Board said they would raise questions with the state Public Service Commission about costs related to the shutdown and how they could affect customers.

The plant has been operating at reduced capacity at times in recent years and didn't operate for three months last spring.

More: Milwaukee Journal Sentinel

Idaho Power Finishes King-Wood River Rebuild

Idaho Power has finished rebuilding the 59-mile, 138-kV King-Wood River transmission line.

The line, which was built in 1962, is one of two that bring power from south central Idaho to a substation in Hailey.

Idaho Power replaced the line's wooden H-frame structures with steel and increased the size of the wire on the line.

More: Idaho Mountain Express

Intermountain Rural Providing Rebates for Cheap Power

The Intermountain Rural Electric Association will return $8.4 million to its customers because its power supplier, Xcel Energy, was able to buy electricity for less than anticipated.

The cooperative will provide rebates averaging $41 per residential customer that will show up as credits on customers' bills next month.

Intermountain Rural has more than 150,000 customers in 10 counties on the southern tier of the Denver metro area.

More: The Denver Post

Glick on Board, FERC Awaits McIntyre

By Peter Key

Richard Glick was sworn in at FERC on Wednesday, giving the commission four members as it awaits the arrival of its new chairman, Republican Kevin McIntyre.

Glick, the general counsel for the Democrats on the Senate Energy and Natural Resources Committee, and McIntyre, the co-leader of the global energy practice at the law firm Jones Day, were confirmed by the Senate on Nov. 2.

Glick, who will serve a term that ending in June 2022, did not respond to a request for comment. The term for McIntyre, who will replace fellow Republican Neil Chatterjee as chairman, ends in June 2023. A FERC spokesman said the agency had no information on when McIntyre will be sworn in.

No Conspiracy

The delays in the commissioners' arrival led some observers to speculate that the Trump administration was purposely dragging its feet so the two could not take part in a vote on the Department of Energy's proposed price supports for struggling coal and nuclear generators.

Last week, Chatterjee attempted to quash that notion after speaking at a Consumer Energy Alliance event.

"I do want to be clear with everybody: You guys are reading way too much into this," Chatterjee told reporters, according to an account in The Hill. "There is no conspiracy here. There is no intentional delay or dragging things out to some nefarious end."

Chatterjee has proposed "interim" protections for threatened generators while the commission considers the department's Notice of Proposed Rulemaking. Chatterjee, the only commissioner who has publicly supported the NOPR, said FERC will act on the rulemaking by Dec. 11. (See *Chatterjee 'We've Moved Past' DOE NOPR*.)

Commissioners Rob Powelson, a Republican, and Cheryl LaFleur, a Democrat, have reacted more warily to the NOPR, expressing concern it could damage wholesale markets. They have declined to take a position on Chatterjee's "interim" proposal. (See *DOE, Pugliese Press 'Baseload' Rescue at NARUC*.)

Glick and McIntyre have not commented publicly on the NOPR. During his Senate confirmation hearing, however, McIntyre said, "FERC is not an entity whose role includes choosing fuels for the generation of electricity."

From left to right: Commissioners Cheryl LaFleur, Richard Glick and (far right) Robert Powelson. Chief ALJ Carmen Cintron (second from right) swore Glick in. | *FERC*

Glick's Experience

Before joining the Senate staff, Glick was vice president of government affairs for Iberdrola's U.S. renewable energy, electric and gas utility, and natural gas storage businesses. Earlier, he served as a director of government affairs for PPM Energy and PacifiCorp, and legislative director and chief counsel to Sen. Dale Bumpers (D-Ark.). During the Clinton administration, he was a senior policy adviser to Energy Secretary Bill Richardson.

He is a graduate of George Washington University and Georgetown Law. He and his wife, Erin, have a son.

FEDERAL BRIEFS

Industry Split on Senate Tax Overhaul

The tax overhaul approved by the Senate early Saturday received mixed reviews from the electric industry.

Edison Electric Institute President Tom Kuhn said the bill, which cuts the corporate tax rate from 35% to 20%, "boosts the economy and increases U.S. competitiveness, creates jobs, encourages private investment in critical energy infrastructure, and keeps energy bills as affordable and predictable as possible."

But the American Wind Energy Association and American Council on Renewable Energy issued a joint statement with a coalition of clean energy groups saying that some provisions will hurt clean energy investment. They cited the Base Erosion Anti-Abuse Tax (BEAT) provision and the impact of the corporate Alternative Minimum Tax (AMT) on investments. "If these provisions are retained, they will result in broad instability and uncertainty for businesses and investors across many sectors, including the clean energy sector," they said.

Malcolm Woolf, senior vice president of policy for Advanced Energy Economy, also had misgivings. "On the one hand, the Senate bill keeps the 2015 promise to maintain the phasedown of energy credits for wind and solar, which the House tax bill undermined, and maintains the important electric vehicle tax credit as well as authority for tax-exempt bonding," he said in a statement. "But the bill does not provide equal treatment for technologies like fuel cells, distributed wind, storage, combined heat and power, geothermal and advanced nuclear, despite the interest of several senators in doing so."

Coal producer Murray Energy lamented that the Senate bill did not repeal the corporate Alternative Minimum Tax, which it said hurts "particularly capital-intensive, leveraged employers, such as coal mining companies."

"This legislation is much worse than the status quo," CEO Robert Murray said in a statement. "Our company will see a significant tax increase resulting primarily from the loss of the business interest expense deduction."

Congressional leaders are expected to announce plans this week for a conference committee to iron out differences between the Senate bill and the House's tax rewrite, which was approved last month. Republicans have vowed to have a bill ready for President Trump's signature before the end of the year. (See *GOP Tax Bill Would Trim PTC, Drop Credit for EVs*.)

Meanwhile, separate from the tax bill, industry lobbyists are asking Congress to provide virtually all coal and nuclear power plants tax credits, according to a report by Axios. American Electric Power and the American Coalition for Clean Coal Electricity are seeking $65 billion in credits for coal generators while Exelon is pushing for $4.8 billion in benefits for nuclear plants.

More: *The New York Times; The Washington Post; Axios*

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FEDERAL BRIEFS

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Decision Date Pushed Back in Solar Trade Case

The date by which President Trump must decide whether to impose tariffs on imported solar products has been pushed back to Jan. 26 from Jan. 12.

The date got pushed back when Trade Representative Robert Lighthizer wrote a letter to the International Trade Commission asking for a supplemental report in the trade case in which the president could impose tariffs.

The commission has 30 days to produce the report, and the president will have 30 days after getting the report to decide, which means the latest day on which he can issue his decision is now Jan. 26.

More: *pv magazine*

NRC to Evaluate Entergy's Safety Measures at Pilgrim

The Nuclear Regulatory Commission this week will begin determining whether it can return the Pilgrim Nuclear Power Plant to a normal level of oversight.

The Plymouth, Mass., plant came under increased scrutiny in September 2015 following several reported safety issues. In response, the commission performed inspections at the site, which led to it issuing a letter identifying corrective actions that plant owner Entergy must carry out.

This week's evaluation is to determine how well Entergy has carried out the actions.

More: *CapeCod.com*

NRC Schedules Final Hearing for FPL's New Turkey Point Reactors

Turkey Point Unit 3 | *NRC*

The Nuclear Regulatory Commission has scheduled its final hearing on Florida Power & Light's application to build and operate two nuclear reactors at the Turkey Point plant on Biscayne Bay about 40 miles south of Miami.

The commission will hold the hearing at its Rockville, Md., headquarters on Dec. 12.

FPL applied to build the reactors, which it estimates could cost as much as $21 billion, in 2008. The commission certified their design in 2011 and has completed safety and environmental reviews of them. If FPL decides to build them, they wouldn't be completed until at least 2031.

More: *Palm Beach Post*

Navajo Station Gets Approval To Stay Open Through 2019

The federal Bureau of Reclamation and Bureau of Indian Affairs have completed their environmental review of the extension of the lease for the Navajo Generating Station, which will enable the coal-fired plant to stay open through 2019.

The Salt River Project, which is one of the owners of the plant, announced the completion of the review on Wednesday.

The Navajo Nation, which leases the land for the plant to its owners, wants to keep the plant and a coal mine that feeds it open beyond 2019, as they employ more than 1,000 members of the tribe.

More: *The Hill*

FERC Urged to Speed Review of Artificial Island

Maryland Gov. Larry Hogan and Delaware Gov. John Carney last week urged FERC to expedite its review of the $278 million Artificial Island transmission line project.

The governors urged FERC to consider alternative cost methodologies presented in June by PJM's Board of Managers that would require electric customers on the Delmarva peninsula to pay 7 to 10% of the project's cost.

A current financing proposal would require Delmarva customers to pay more than 90% of the project's cost, while receiving few of its direct benefits.

More: *The Associated Press*

Group Appeals BOEM Reaffirmation Of Offshore Wind Lease

The Alliance to Protect Nantucket Sound said last week it has appealed a September decision by the Interior Department's Bureau of Ocean Energy Management that reaffirmed Cape Wind's long-term federal lease of 46 miles of Nantucket Sound for an offshore wind farm.

More: *Cape Cod Times*

STATE BRIEFS

MASSACHUSETTS

DPU Grants Eversource Lower Rate Increases than Requested

The Department of Public Utilities on Thursday granted rate increases for Eversource Energy that were much less than the ones sought by the utility.

The department said Eversource's customers in eastern Massachusetts will pay an additional $12 million a year while its customers in western Massachusetts will pay more than $24 million more annually.

Eversource had sought an increase of $90 million for both regions combined.

More: *The Boston Globe*

State Awards Agricultural Energy Grants

The administration of Gov. Charlie Baker has awarded $908,259 in agricultural energy grants to 29 farms.

The Department of Agricultural Resources says the grants are expected to save farmers a collective $200,000 per year and reduce greenhouse gas emissions by 660 tons annually.

Most of the grants are for solar photovoltaic energy systems. Others are for more unusual projects, such as "heat pads for piglets" at Shinglebrook Farm in Shelburne.

More: *The Republican*

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State Briefs

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MICHIGAN

State, Enbridge Reach Temporary Agreement on Line 5

The state and Enbridge last week announced an agreement to enhance safeguards on Enbridge's Line 5, dual oil and natural gas liquids pipelines that run under the Straits of Mackinac.

The agreement follows the release of a contractor's analysis on alternatives to the pipelines and reports of widespread protective coating gaps and damage that Enbridge knew about three years ago but did not disclose until earlier this fall.

The agreement is not meant to be permanent. The state and Enbridge will try to negotiate an additional agreement by next August. If they can't, the state could shut down the pipelines.

More: *MLive*

MINNESOTA

Community Solar Gardens Boosting State's Solar Capacity

The state's solar capacity grew by 114 MW, to 612 MW, from July through October, according to the Department of Commerce. It grew 366 MW in the first 10 months of 2017, more than doubling 246 MW of solar capacity the state had at the end of 2016.

Most of the recent gains came from community solar gardens built for Xcel Energy's Solar*Rewards Community program. As of Oct. 31, the state had 200 MW of community solar gardens, 197.5 MW of which are designated for Xcel's program.

More: *KELO*

MISSOURI

Clean Line Files Briefs in Appeal of PSC's Grain Belt Express Denial

Clean Line Energy Partners last week filed briefs in the state Court of Appeals' Eastern District challenging the Public Service Commission's rejection of its request for a certificate of convenience and necessity for a portion of its $2.3 billion Grain Belt Express transmission project.

The briefs claim the PSC erred in denying Clean Line's application, citing the commission's deference to a ruling involving another transmission project by the court's Western that said the PSC couldn't approve the project until each county in the project's path had approved it.

Oral arguments in the case are scheduled for February but could be rendered unnecessary if the state Supreme Court agrees to Clean Line's request that it hear the case.

More: *St. Louis Post-Dispatch*

Ameren Files with PSC to Create Subscription Wind Program

Ameren Missouri last week filed a proposal with the Public Service Commission to create the Renewable Choice Program, which would allow cities and companies that are Ameren customers to subscribe to wind power for up to 100% of their electricity needs.

Ajay Arora, Ameren's vice president of environmental services and generation resource planning, said the program would be a follow-up to the plan the company filed with the PSC in September to spend $1 billion to add 700 MW of wind generation by 2020.

Arora said the program would be the first of its kind offered by an investor-owned utility in the state. Several large Ameren customers have expressed interest in the program, he said.

More: *St. Louis Post-Dispatch*

NEBRASKA

TransCanada Asks PSC to Reconsider Decision on Keystone

TransCanada has asked the Public Service Commission to reconsider its order approving an alternate route for the Keystone XL pipeline.

A TransCanada spokesman said the company was seeking a "clarification" on the PSC's decision. The route for the pipeline approved by the PSC was not the route that TransCanada preferred.

More: *Reuters*

NEW HAMPSHIRE

PUC Approves Eversource Sale Of Fossil Plants for $175M

The Public Utilities Commission approved Eversource Energy's sale of three fossil fuel plants and two combustion turbines for $175 million to Granite Shore Power, which is a newly formed 50-50 partnership between Atlas Holdings and Castleton Commodities International.

The commission is still considering Eversource's proposed sale of nine hydroelectric facilities to Hull Street Energy for $83 million.

Both sales are part of a two-decade effort to deregulate the state's power market.

More: *New Hampshire Union Leader*

NEW MEXICO

PRC Dismisses Challenge to Decision on PNM Solar Purchase

The Public Regulation Commission on Wednesday dismissed a request by New Energy Economy to overturn a Nov. 15 decision to accept Public Service Company of New Mexico's (PNM) plan to buy 50 MW of power from Affordable Solar for $44.63/MWh.

New Energy's executive director, Mariel Nanasi, argued that PNM last year received bids from other companies as low as $41.63/MWh. She also pointed out that the commission earlier this year approved a plan in which PNM contracted with Affordable Solar for the planned Facebook facility in Valencia County with a ceiling price of only $39.85/MWh.

New Mexico Industrial Energy Consumers, which also opposes the plan, has appealed the commission's decision to the state Supreme Court.

More: *Santa Fe New Mexican*

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STATE BRIEFS

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NEW YORK

NY Green Bank Issues RFP For Clean Energy Investment

NY Green Bank said Friday it has issued a request for proposals related to its goal of raising at least $1 billion in third-party capital to support the state's energy goals.

The division of the New York State Energy Research and Development Authority seeks to bring on a firm or group of firms to evaluate strategies for raising, investing and managing the money.

NY Green Bank said the issuance of the RFP was an important step in its previously announced intention to expand availability of financing for clean energy projects both within and beyond the state.

More: *NY Green Bank*

Cuomo Announces $3.5 Million for EV Projects

The state will provide up to $3.5 million to fund projects to speed the use of electric vehicles, reduce the cost of installing and running EV charging stations, and show how EVs can be used to boost grid resiliency, Gov. Andrew Cuomo said Thursday.

The New York State Energy Research and Development Authority is seeking proposals for research projects that show the potential impact of EVs on job growth, technical advances and the overall economy. The agency is particularly interested in proposals for innovative business models and technologies to better manage the relationship between EVs and the grid.

More: *Gov. Andrew Cuomo*

NYCHA Posts List, Map of Sites for Solar Development

The New York City Housing Authority has posted a list and interactive map of more than 200 sites across the city that it will be making available for solar development under its Public Purpose Shared Solar program.

Under the program, smaller rooftops are made available at low or no cost to community-based organizations and nonprofits teaming up with solar developers to install community shared solar systems that will serve low- to moderate-income households and provide green jobs for housing authority residents.

The program is part of a housing authority initiative to install 25 MW of renewable energy capacity by 2025.

More: *NY Solar Map*

Empire State Connector Seeking Expressions of Interest

Empire State Connector Corp. has gotten permission from FERC to seek nonbinding "expressions of interest" from entities interested in delivering power to the 1,000-MW, HVDC transmission line it wants to build from Utica to New York City.

The company intends to submit plans for the line to the Public Service Commission by the end of the year and hopes to have it in service by 2022.

The line, which would be buried under the Erie Canal and Hudson River, is meant to carry hydroelectric or nuclear power downstate. The company developing it is backed by two Toronto companies — oneGRID and Forum Equity Partners.

More: *Albany Times Union*

NORTH DAKOTA

PSC Commissioner Named Secretary of OMS


Fedorchak

Public Service Commissioner Julie Fedorchak has been appointed secretary of the Organization of MISO States.

The appointment also gives Fedorchak a spot on the MISO Advisory Committee, which advises the MISO Governing Board.

More: *The Bismarck Tribune*

PSC Approves New Xcel Tx Line near Fargo

The Public Service Commission on Wednesday issued a certificate of public convenience and necessity for a 5-mile transmission line in the Fargo area Wednesday that it hopes will improve Xcel Energy's reliability.

The 115-kV line will connect two substations on Fargo's north side. It will largely follow an existing rail line from west of I-29 to southwest of the North Dakota State University campus.

The commission also issued an amended route permit for a 345-kV transmission line to run from a new substation near Ellendale to the South Dakota border. The North Dakota portion of the project, proposed by Montana-Dakota Utilities and Otter Tail Power, is only 9 miles long, but it will ultimately run to Big Stone City, S.D.

More: *Forum News Service*

RHODE ISLAND

National Grid Seeks Electric, Gas Rate Hikes

National Grid last week filed a request with the Public Utilities Commission to increase its electric distribution rate by an amount that would boost its annual revenue by $41.3 million.

The company said the increase would hike monthly bills by 6% for residential customers and 3 to 9% for commercial industrial customers, depending on their size and how much power they use. National Grid is also seeking an increase in its natural gas distribution rate that would boost its annual revenue by $30.3 million.

Gov. Gina Raimondo and Macky McCleary, administrator of the Division of Public Utilities and Carriers, blasted the request.

More: *Providence Journal; National Grid*

Final Hearings on Clear River Pushed Back to March

The Energy Facility Siting Board approved a 90-day extension to the permitting process for the $1 billion natural gas-fired power plant that Invenergy wants to build in Burrillville.

The extension, which was granted in response to a motion from the Conservation Law Foundation, pushes back the start of final hearings on the Clear River Energy Center until March.

Deliberations for the application were supposed to wrap up early this year, but Invenergy had difficulty securing a necessary source of water for the combined cycle facility's secondary steam turbines.

More: *Providence Journal*

NERC Parts Ways with Chief Security Officer

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Cauley's Nov. 9 arrest on domestic abuse charges.

NERC did not respond to a request for comment Monday.

Sachs has joined Ridge-Lane LP, a merchant bank co-founded by former Homeland Security Secretary and Pennsylvania Gov. Tom Ridge. In an email, Sachs called his departure from NERC "a strategic move for me, which will allow me to assist other companies and organizations as they grow and develop."

"I look forward to the next chapter of my career, and to be able to give back to others many of the lessons I have learned," he added.

The ESCC, which serves as a liaison between industry and the federal government, is dominated by CEOs of investor-owned utilities.

Tim Roxey, a NERC vice president who serves as chief operations officer for the E-ISAC, was named interim chief security officer with responsibility for overseeing the E-ISAC and directing security risk assessment and mitigation activities. Bill Lawrence, a senior director with the E-ISAC who led GridEx IV last month, will assume day-to-day management of the center. (See *Ukraine Attacks, 'Fake News' Color NERC GridEx IV Drill*.)

MidAmerican Energy CEO William Fehrman, vice chair of the NERC Members Executive Committee, will provide "strategic counsel and guidance" on the E-ISAC's expansion during the search for Sachs' replacement, NERC said. Fehrman referred an interview request to NERC.

The E-ISAC is the primary security communications channel for the electricity sector, helping grid operators and others prepare for and respond to cyber and physical threats.

NERC's 2018 Business Plan calls for improving the E-ISAC's "technical and analytical capabilities with a goal of becoming the electricity industry's leading, trusted source for analysis and sharing of security information." The E-ISAC's staffing will increase to 29 full-time equivalent employees from less than 20, funded by a $21.9 million budget, a $3.3 million increase from 2017.

"The long-term strategic plan is to transform the E-ISAC into a world-class intelligence collecting and analytical capability for the electricity industry," according to the plan.

NERC General Counsel Charles Berardesco, who was appointed interim CEO following the Nov. 20 resignation of former CEO Gerry Cauley, said in a statement that he was "confident the E-ISAC, under Tim and Bill's leadership, will continue to effectively carry out its responsibilities." (See *Cauley Resigns; NERC Launches Search for Replacement*.)

Ridge-Lane says it sponsors "public-private partnerships to finance social infrastructure and advance modern urban developments across the U.S., as well as specialty venture capital and corporate development services to commercialize and scale innovative technology companies."

The company did not respond to a request for comment.

Mexico Market Director Seeks Increased Participation

Continued from page 1

during Mexico's third long-term auction in November. Only 16 offers were completed, though in larger packages than in the first two auctions.

According to Mexican energy consulting firm Zumma rg+c, the auction resulted in a world-record low price for wind energy, at $17.76/MWh. But the company said solar energy still accounted for 55% of the energy and clean energy certificates in the auction, with a price of $18.93/MWh.

Only three load-serving entities participated on the buyer-side: the state-owned Federal Electricity Commission (CFE); Spanish multinational Iberdola; and Mekent, an electricity retail division of CEMEX Energia, the second-largest construction materials company in the world. Together they bought a combined 593 MW/year of capacity in the national interconnected system, 5.49 TWh/year of energy and 5.95 million clean energy certificates per year.

Valenzuela said he has focused on increasing the number of private buyers by aggregating qualified buyers. CENACE hopes to attract more participants by establishing a clearinghouse like those used by U.S. RTOs, he said. The clearinghouse is designed to allow buyers other than CFE to participate in the auction process.

Valenzuela said implementing Mexico's market reforms has been a "big challenge" but pointed to the speed with which the market has ramped up operations. Market reform was written into the country's constitution just three years ago, and CENACE was able to implement a short-term market in less than a year and a half and run its first long-term auction within five months, he said.

Roll-out of Mexico's spot market has been postponed to give market participants more time to develop market-rate — rather than cost-based — bids.

"The [timing] is very tight. Not just for us, but even for the participants, because they need to understand … the process," he said.

Valenzuela's comments came during the second of what Mexican representatives hope will be a recurring breakfast. Jonathan Pinzon, a partner with Zumma, said he and fellow consultant, Que Advisors' Peter Nance, hope to schedule eight to 10 meetings in 2018, focusing on intimate gatherings that avoid "death by PowerPoint."

"We bring together different actors from across the industry," Pinzon said. "We've always thought that small-group partnerships help develop further relationships in the market. It also brings out some good questions not reflected in PowerPoint."

Pinzon credited GCPA Executive Director Tom Foreman for helping the new effort, recognizing that Mexico is also part of the Gulf Coast. The GCPA has scheduled its next conference on the Mexican power market for May 16 in Mexico City.

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