RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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Distributed Energy Resources Coast to Coast

Distributed energy resources was the hot topic of the week: three different conferences in three different regions of the country were devoted to discussing the changing market trends and RTOs' efforts to respond to them. ***RTO Insider*** was at all of them.

Clockwise from top from left: smart thermometer *(DOE)*; solar-powered house in Boston; the Tesla Powerwall *(Tesla)*; and hybrid car charging station in San Francisco.

FERC Considers Changes to Market Power Analyses

By Rich Heidorn Jr.

WASHINGTON — FERC said last week it is considering changing how it evaluates market power in electric utility mergers and applications for market-based rate authority (MBRA).

Most of the changes the commission is considering in its Notice of Inquiry (RM16-21) would affect merger reviews.

The commission noted that its market power evaluation for mergers, which are regulated under Section 203 of the Federal Power Act, differs from that used in MBRA applications under Section 205.

"While some of those differences may be appropriate, others may not be," the commission said, adding that it was seeking to "harmoniz[e]" the two.

The commission asked for comment on whether it should make the following changes in Section 203 reviews:

- Use a simplified analysis for transactions that typically don't raise market power issues;
- Add supply curve and market share analyses;
- Modify how capacity under long-term power purchase agreements is attributed;

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Competitive Power Ventures Lobbyist, Former Cuomo Aides Named in Bribery Indictment

By Ted Caddell

An executive for power plant developer Competitive Power Ventures, two former aides of Gov. Andrew Cuomo and seven others were named in a broad bribery indictment by federal authorities in New York on Thursday.

Kelly Jr.

Peter Galbraith Kelly Jr., CPV's head of external affairs and government relations, was named in the indictment. CPV is only identified as "the energy company" in the indictment, and the company itself was not a named defendant.

One of the former aides, Todd R. Howe, has already pleaded guilty to several charges, including extortion, wire fraud and conspiracy, and has agreed to testify against the others. According to the indictment and

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10837 Deborah Drive ▫ Potomac, MD 20854 ▫ (301) 983-0375 ▫ info@rtoinsider.com ▫ www.rtoinsider.com ▫

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CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr. 202-577-9221

Contributing Editors
Ted Caddell 434-882-5589
Suzanne Herel 302-502-5793

Production Editor
Michael Brooks 301-922-7687

MISO Correspondent
Amanda Durish Cook 810-288-1847

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

CAISO/West Correspondent
Robert Mullin 503-715-6901

ISO-NE/NYISO Correspondent
William Opalka 860-657-9889

PJM Correspondent
Rory D. Sweeney 717-679-1638

Subscriptions and Advertising

Chief Operating Officer / Co-Publisher
Merry Eisner 240-401-7399

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 983-0375

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FERC Considers Changes to Market Power Analyses

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- Require submission of documents already required by other federal antitrust regulators; and
- Develop a more precise definition or test of *de minimis* in determining when a full competitive analysis screen is unnecessary in merger reviews.

The commission also is considering improving its single pivotal supplier analysis in MBRA applications and adding one to Section 203 evaluations.

Chairman Norman Bay said the proposed changes were not the result of concerns over a specific merger.

"There certainly have been a number of mergers over the last few years in the electric industry, but I don't think there was any one specific act that led us to review the screens that we use in conducting our reviews under Section 203 of the FPA," he said in a press conference after Thursday's commission meeting. "I think more it's a matter of continually striving for improvement as an organization or as an agency. And in order to do that, from time to time, you have to take a step back and examine what you've been doing and ... ways to improve what you're doing."

Comments will be due 60 days after the notice's publication in the *Federal Register*.

Adding Pivotal Supplier Screen

The commission said it is looking for new tools to ensure the effectiveness of its market power reviews, including the use of wholesale market share and pivotal supplier screens currently used in Section 205 MBRA reviews.

Merger applicants are currently required to perform a competitive analysis screen unless they can show that the acquisition does not increase their generation capacity in the relevant geographic markets or that the increase is *de minimis*.

The screen includes a delivered price test, which has been essentially unchanged since its introduction in 1996 and generally focuses on the short-term energy market "with far less detail and attention given to the other relevant products," FERC said.

In contrast, the pivotal supplier screen measures a seller's ability to exercise market power based on its uncommitted capacity at the time of annual peak demand in the relevant market. A seller passes the screen if wholesale load can be served without any of the seller's capacity participating.

Although pivotal supplier tests are usually applied to energy-only markets, the commission said they could be applied to capacity and ancillary service markets under both sections 203 and 205. "Adding a pivotal supplier test to the commission's review of a Section 203 application could make the commission's analysis more effective because it would take into account the ability to meet demand, in addition to supply conditions, in screening for potential market power," FERC said.

But the commission said it also seeks to improve the test because MBRA applicants "rarely fail" it.

"In many cases, the results of the pivotal supplier analysis indicate that the study area's wholesale load can be met solely by remote suppliers, a result that is unlikely in practice," FERC said. "The commission intended that the indicative screens would serve as a conservative threshold. However, with experience, this does not seem to be the case."

As a result, the commission said it is considering whether to replace the current wholesale load proxy, defined as the average of the daily peak native load during the month in which the annual peak load day occurs.

FERC is considering replacing that input with the study area's annual peak load — peak load not reduced by the proxy for native load obligation.

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Correction

An article in last week's issue (*Natural Gas, Offshore Wind, Storage Seek Their Places in NY's Future*) incorrectly suggested the Natural Resources Defense Council is affiliated with the New York Offshore Wind Alliance. The wind group is affiliated with the Alliance for Clean Energy New York.

CAISO NEWS

California Distributed Energy Summit

Utility Planners Confront the Complexity of DER

Need Seen to Improve Forecasts, Eliminate 'Silos'

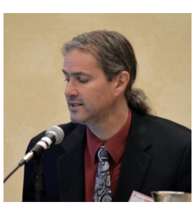
By Robert Mullin

SANTA MONICA, Calif. — Optimizing distributed energy resources and reducing greenhouse gas emissions cost effectively will require improved forecasting and the elimination of regulatory silos, speakers told Infocast's California Distributed Energy Summit last week.

Margie Gardner, executive director of the California Energy Efficiency Industry Council, opened the two-day conference with a question that framed the big picture: "What's the purpose of integrating DERs into long-term procurement?"

The three speakers on the first panel offered variations on a theme.

For Pacific Gas and Electric, "integration means selecting that set of resources" that provides the least-cost solution to reduce GHGs while also maintaining system reliability, said **Antonio Alvarez**, renewable integration manager for the utility.



The California Public Utilities Commission believes that DER can help the state meet its carbon reduction goals while providing "safe reliable service at just and reasonable rates," said **Pete Skala**, deputy director of costs, rates and DER.

"The question is, to what extent and where do they provide costs and benefits?" Skala said. The regulators' goal is developing the "right amount of DER" to allow ratepayers, utilities and DER providers to all see benefits.

Costs and reliability "are definitely major drivers" for the Southern California Public Power Authority (SCPPA), said **Ted Beatty**, director of resource and program development for the joint planning agency, which represents the Los Angeles Department of Water and Power and 11 smaller municipal utilities.

"We have some small utilities, too, so we kind of have a wide range of needs there," Beatty said. "But in general, they all have needs to look at planning for DERs."

Forecasting Challenges

SCPPA's members meet monthly to discuss issues around forecasting — a process becoming more difficult because of the unpredictability of DER penetration. DERs don't connect to the grid via the traditional utility planning process.

Members are trying to grasp the technical and financial implications of increased DERs and understand customer trends to gauge the potential distributed solar capacity in their service territories. That effort has been hampered by the fact that some SCPPA members haven't installed smart meters at customer sites.

"If you don't have [customer data], you don't really know what's going on in your system," Beatty said. "All you see is the net load that moves up and down, but you don't know exactly why."

Alvarez said that his utility's long-term planning process relies on demand forecasts from the California Energy Commission (CEC), which factors in energy efficiency and distributed generation gains as well as energy consumption.

Recent forecasts put California power consumption growth at less than 1% per year, but that number could turn negative with increased energy efficiency mandates embedded in legislation passed last year (SB 350). That could exacerbate the forecasting complexity brought on by increased DERs.

"This is not new," Alvarez said. "We've seen energy efficiency cutting in half — or more — the growth in demand."

Next year, the CPUC will require each of California's load-serving entities to file an integrated resource plan that prioritizes emission reductions alongside other more standard requirements, such as resource diversity, reliability and cost-effectiveness. (See *Integrated Resource Planning on the Horizon for California*.)

The revised IRP will provide the industry an opportunity to improve forecasting of DER, Alvarez said.

The IRP is an "optimization process" that seeks to determine the least-cost mix of resources to reliably meet California's goals for energy efficiency, renewable generation and electrification of transportation. "I think at the end of the integrated resources plan, you actually have a demand forecast and a DER forecast," Alvarez said.

Utilities have to look at more of a range than rely on specific forecasts, added Beatty, who suggested the industry should be employing scenario planning.

"When you're looking at a forecast, you have to look at the different paths that are out there," Beatty said. "Today I can't predict five years ahead how much solar is going to come in [to the system], how much storage is going to be added to the system — or anything, for that matter."

Skala said that although traditional "utility-scale, one-directional flow" grid planning is adapting to recognize the bidirectional flows stemming from DER, additional changes are still needed.

Utility planners "are a conservative bunch by nature." When you talk about "safe and reliable service at just and reasonable rates while we achieve the state's carbon goal, they only hear the word 'reliable,'" Skala joked.

The variety of distributed resources and energy efficiency efforts adds "thousands of measures to the planning process," he

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CAISO NEWS

California Distributed Energy Summit

California Regulatory Model Fosters — and Hinders — DER Integration

By Robert Mullin

SANTA MONICA, Calif. — Attendees at last week's Infocast California Distributed Energy Summit received a crash course in the complexity of developing policies on distributed energy resources in a state that already boasts nearly 5,000 MW of rooftop solar.

The takeaway: Conflicting regulatory drivers and misaligned utility business models must be addressed to ensure the value of DERs is maximized and that consumers aren't saddled with the costs of stranded assets.

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From left to right: Brandon Smithwood, SEIA; Tom Flynn, CAISO; Will Speer, San Diego Gas and Electric; and Jim Baak, Vote Solar. | *RTO Insider*

Utility Planners Confront the Complexity of DER

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continued. "It becomes a very messy beast for conservative grid planners to try to figure out and incorporate into their work."

Adding DER to the Planning Mix

Gardner asked the panelists to pick the most important thing that could be done to better incorporate DERs into the planning process.

"We need to have better models that analyze customer decision-making [and] factor all those together to figure out where the customer is going to go," responded Beatty. "Once we know that, I think we can kind of follow along with them."

Solar is the most significant DER for SCPPA utilities, with some members having already reached their net energy metering caps under state rules. Those utilities also control a large amount of utility-scale solar, which undermines the cost-effectiveness of distributed solar that generates during the same intervals.

"It's a challenging market for these guys, and it's difficult to figure out where we're going and which DERs are the customers' choice," Beatty said.

"There needs to be a lot more alignment within the state agencies and the California Independent System Operator in terms of all the various planning activities that are ongoing," Alvarez offered.

Alvarez would like to see the California Air Resources Board, CEC and CPUC coordinate their efforts to produce more reliable demand and DER forecasts, eliminating the agencies' planning "silos."

"It would be helpful to get some of those results as an input into the electric IRP process, so we can actually see the interaction between the different sectors of the economy — where you can get the best reductions in emissions," Alvarez said. "If you're trying to find what's the optimal solution for the state and the electric sector, you need to have a common set of metrics."

Skala concurred with Alvarez's view on the need to align regulatory proceedings that require utilities to procure separate types of resources — such as energy storage, demand response and energy efficiency — under different state programs.

"The more we can get process alignment in place, the easier it's going to make on markets," Skala added.

'Adolescent' Grid

The overlapping nature of California's regulatory proceedings and the complication of integrating DER inspired a humorous analogy from Skala about the "nanny state" approach of setting various resource targets and the rules that apply to them.

"That caused me — in thinking about nannies — to think about the the grid in the child-rearing sense," said Skala, the father of a 14-year-old daughter.

Historically, the grid — or demand, rather — has been a baby that's been fed since the first light bulb, Skala said.

"And now we're squarely in the adolescent period ... so it's a very confusing time, but it's also a really important time developmentally," Skala continued. "It's really important to have clear and simple rules ... that are designed to help customers and grid planners and everybody in that relationship make healthy choices."

That will require sending clear signals to market participants, he added.

"But we also need to figure out what the utility model of the future looks like in that world, because if we don't — to carry the analogy — we will have an empty-nester syndrome," Skala said. "We've got to work it out in a way that works for the parent too."

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California Distributed Energy Summit

California Regulatory Model Fosters — and Hinders — DER Integration

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Moderating a panel on regulatory issues, **Brandon Smithwood**, California state affairs manager at the Solar Energy Industries Association (SEIA), let panelists weigh in on the "alphabet soup" of agency proceedings intended to foster the integration of DER.

"To us, DER is anything that's connected to the distribution level," said **Tom Flynn**, storage and DER policy manager at CAISO. "Any resource of any type, any technology. It doesn't matter to us whether it's in front of the meter, behind the meter — but it's connected to the distribution grid, connected to the grid below the ISO's grid."

A few years ago, DER advocates expressed interest in aggregating those resources to participate in CAISO's wholesale market, which requires participating resources to be at least a half-megawatt in capacity, Flynn said.

In response, the ISO allowed DERs to aggregate as a "virtual resource" distributed across multiple pricing nodes within the ISO's system. That program, known by the acronym DERP — or Distributed Energy Resources Provider — was approved by FERC in June (ER16-1085). (See *CAISO Tariff Change Would Extend Market to DER*.)

Since then, the ISO has started another initiative called Energy Storage and DER — or ESDER. Among other things, that effort would allow developers to use storage to offset load behind the meter. Unlike other DERs such as rooftop solar, that storage could then bid demand response into the wholesale market.

Storage, "in effect, creates one of the first multiple-use applications," Flynn said, noting that it can simultaneously participate as a supply- and demand-side resource.

Flynn noted that the California Public Utilities Commission has initiated a proceeding that explores similar issues, such as multiple-use applications; the ability to provide services to multiple entities; station power for storage; and interconnection processes and metering rules for DERs participating in wholesale markets.

More Letters for the Regulatory Soup

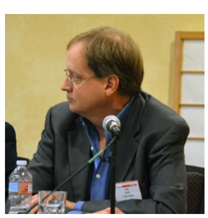
Will Speer, director of electric system planning at San Diego Gas and Electric, tossed a few more letters into the regulatory alphabet soup, bringing up the CPUC's Integrated Resources Plan and Distributed Resources Plan.

The IRP seeks to help California utilities find the least-cost mix of resources, including DER, to meet the state's greenhouse gas reduction goals. (See *Integrated Resource Planning on the Horizon for California*.)

The goal of the DRP is to determine the ability of a utility's distribution system to accommodate DER, Speer said.

"The first requirement was to complete an integration capacity analysis," he said. "The next big piece of this is a locational net benefits analysis. It's really looking at — for the locations of feeders — what is the locational net benefit of DERs in those spaces?"

Another component of the plan: demonstration projects to examine the locational benefits of DER and the use of microgrids.



Jim Baak, director of grid integration at nonprofit policy advocacy group Vote Solar, said the number of acronyms indicates the complexity of the regulatory landscape.

"In typical public utility code fashion ... we're very good at parsing issues into siloed proceedings and programs," Baak said.

To provide a sense of the complexity, Baak listed the topics being treated under separate and overlapping proceedings: electric vehicles, DR, energy efficiency, interconnection rules, the renewable portfolio standard, time-of-use rates, net energy metering, general rate cases, integrated resources planning and energy storage.

That creates a lot of "conflicting drivers" for DER, Baak said.

One of those drivers is the traditional utility planning process, which focuses on loads, resources and forecasting.

Another driver is state policy objectives, which seek to reduce GHG emissions, support jobs and enhance customer choice in energy supply.

And then there's yet another layer: customer demand and the market forces responding to it.

'Evolving Customer Preferences'

Although the industry recognizes consumer demand in terms of forecasting and deployment of DER, the planning process is not fully factoring in long-term changes in consumer behavior, Baak contended.

New industry entrants such as Google, Microsoft, General Electric and ADP are seeking to provide services to consumers about how they "consume, produce and think about energy," Baak noted, asking how that development fits with the traditional utility planning structure and business model.

"If you think about it for a while ... there's not a real good fit," he said. "We're sort of trying to overlay this existing infrastructure that we have in the regulatory process with market forces that are happening."

DER is comparable with the "disruptive" technologies and processes that gave rise to businesses like Uber and Airbnb, and something that can't be forced into traditional utility structures, Baak said.

"And the one piece that I feel is missing in California is the vision for this," he said.

Baak acknowledged that the technical

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proceedings seeking to identify ideal locations for implementing distributed resources are necessary for maintaining reliability. But he also wondered how well equipped they are for meeting state policy objectives and consumer needs.

"What happens when a customer wants to put in an electrical vehicle or solar system in an area of the grid where there are not necessarily grid benefits for doing so?" Baak asked.

And Baak pointed to the elephant in the room: the need to reform the utility business model, an effort that requires regulatory input and oversight.

"We do need to recognize that there's a misalignment between the utility's financial objectives and the policy objectives that we have here for DER," Baak said. Utilities are being asked to defer investment in infrastructure on which they could earn a rate of return for shareholders and instead procure third-party DERs.

In May, New York regulators approved an order revamping their utility business model, creating new revenue streams tied to utilities' willingness to become "distribution system platform providers" that plan, operate and administer markets for distribution-level services. The order creates incentives based on how well utilities meet goals for GHG reductions, system efficiency and energy efficiency. Customer satisfaction surveys of DER providers also will be a factor. (See *NY REV Order Revamps Utility Business Model*.)

California has put no such mandate in place, just a set of incentives and "a vague idea of where we think this should go," Baak said.

"We have to make sure the utilities are structured in a way, and financially awarded in a way, that they support the policy goals of the state as well as the market forces that are driving this," Baak said.

Speer concurred with Baak up to a point, contending that the state's support of DER is focused on a goal.

"It's not just to promote DER to promote DER, it's to achieve reductions in GHGs," Speer said. "I do think that vision's out there, but there is a lot of work to be done."

"I get a sense in everywhere that we go that we want it to happen today," Speer continued, adding that customers will suffer without proper planning.

Baak said Vote Solar feels "a sense of urgency," both because of the state's climate goals and an anticipated increase in consumer demand for DER as prices decline.

CAISO's Flynn acknowledged that "evolving customer preferences" — and not just public policies — are driving the adoption of DER.

DER owners' desire to maximize their investments led the ISO to begin developing ways for DERs to access its wholesale markets.

The ISO is starting to see DER as a more significant supply resource, something that can both offset and serve more load.

Keeping Distribution in the Loop

But with that trend comes increased effects on the utility distribution system, which "are going to more and more affect the transmission system — and vice versa," Flynn said.

Distribution utilities are developing the capabilities to manage those effects, but increased participation by DER in wholesale markets will require improved data transfers between CAISO and utilities, he said.

Flynn pointed out that an ISO dispatch order to a DER market participant — which puts power on the distribution grid hosting the resource — leaves the distribution utility "completely out of the loop in terms of information."

"They don't know what that DER is offering to provide us in the wholesale market," Flynn said. "They don't know that we've issued a dispatch instruction to them."

That has alerted CAISO to a "major gap" in its processes: the need to improve data exchange with utilities — something just as important to the ISO, which needs to ensure a predictable response by a DER.

"I think everyone's goal here is to optimize the use of DER," Flynn said. "We don't want to leave value on the table."

Baak brought the consideration of that value into the context of the regulatory process, noting that Southern California Edison has submitted a rate case proposing more than $2 billion in distribution grid investment to facilitate increased deployment of DER.

While Baak acknowledged the need to modernize the grid, he contended that some of that investment could be displaced by using DERs more cost-effectively.

His organization is concerned that without a utility business model reformed to accommodate DER, regulators will sanction unnecessary investment in utility infrastructure that will remain as a fixed cost in the rate base for 20 years. As the growth of DER allows more customers to supply their own energy, the utility rate base will decline.

"Well, what happens to that fixed-cost recovery?" Baak asked. "Now you're exacerbating the problem of fixed-cost recovery over a diminishing rate base. What happens to rates?"

Those issues will have to be resolved in a way that supports the state's energy and environmental goals, Baak contended.

"We're concerned that, because these proceedings are moving forward independently without that vision, we're going to end up with a solution in the end that's less cost-effective for consumers."

"We're sort of trying to overlay this existing infrastructure that we have in the regulatory process with market forces that are happening."

Jim Baak, Vote Solar

ERCOT NEWS

Texas PUC Expresses Doubts over NextEra-Oncor Deal

By Tom Kleckner

"I have frankly been offended by [the merger agreement], but it is what it is. I don't know where the $275 million is coming from, but it can't be from Oncor's ratepayers."

Ken Anderson, Public Utility Commission of Texas

NextEra Energy's bid to acquire Texas' largest electric utility, which cleared a U.S. bankruptcy court earlier this week, may have to navigate some choppy waters with state regulators.

At the Public Utility Commission's open meeting Thursday, Chairman Donna Nelson and Commissioner Ken Anderson both expressed concerns with NextEra's proposed $18.7 billion purchase of Oncor.

Anderson said his concern is with the $275 million termination fee to be paid to NextEra should the company be out-bid by a last-minute competitor, or if the commission rejects the sale or imposes overly "burdensome" conditions. Nelson said she was concerned about the impact on competition.

Anderson said he has no problem with the termination fee itself, but with how it is structured.

"This merger agreement … appears to be an effort to really tie the commission's hands in the proceeding," he said. "If I read the merger agreement and if the commission rejects the transaction in its entirety as not in the public interest, subject to some caveats, there's no termination fee.

"If, on the other hand, the commission purports to approve it, but with what they call burdensome conditions … that could have a material adverse effect on NextEra or its credit rating … the result is they could walk the deal and get $275 million. Now that's an extraordinary requirement."

'Offended'

"I have frankly been offended by [the merger agreement], but it is what it is," Anderson added. "I don't know where the $275 million is coming from, but it can't be from Oncor's ratepayers."

Anderson said he wanted to explain his concern "so the potential applicant, if it wants to, can address them." The commissioner admitted he has not reviewed the merger agreement in detail, but he promised to file a memo "maybe" next week that fully explains his viewpoint (Docket No. 42750).

"Burdensome" conditions sank a previous bid to buy Oncor from its bankrupt parent, Energy Future Holdings, when creditors objected to the PUC's conditional approval in March of Hunt Consolidated's offer. One of the commission's requirements was that the Hunt group share potential tax savings with the utility's ratepayers. (See Hunt Reopens Oncor Bid in Lawsuit Against PUCT.)

For her part, Nelson said she is concerned with the deal's tax implications and its effect on ERCOT's competitive market. The Internal Revenue Service earlier this summer issued a ruling that eliminates a potential $4 billion tax liability for its remaining assets, power generator Luminant and electricity retailer TXU Energy.

Anderson noted NextEra has "substantial competitive assets" in ERCOT that could give the company an unfair advantage, a position Nelson agreed with. Brandy Marty Marquez, the PUC's third member, was silent during the discussion.

"As this transaction has progressed, it does feel in many ways like a step backwards … with respect to [Oncor's] ownership," Nelson said. "The reason the [ERCOT] market is restructured the way it was with separate and regulated [transmission and distribution providers] was to grant generators and retailers access to customers and a way of serving those customers."

Oncor is not a separate, unbundled company like most in the ERCOT market. As part of EFH's leveraged buyout of TXU Corp. in 2007, the commission required Oncor to be ring-fenced from its sister companies with a separate, independent board of directors.

"The utility press says part of the reason NextEra buys Oncor is they continue to invest in generation and take advantage of the production tax credits," Nelson continued. "I do want to look at those, as well."

An Oncor spokesman declined to comment on the commissioners' statements.

OK from Bankruptcy Court

On Sept. 19, NextEra won approval from the U.S. Bankruptcy Court in Delaware of its bid for Oncor after increasing its offer by $300 million in cash. The company said it would also make other changes to satisfy EFH creditors (Docket No. 14-10979).

EFH's legal counsel told U.S. Bankruptcy Judge Christopher Sontchi during a hearing that unsecured creditors will now receive an additional $450 million. NextEra will pay $4.4 billion in cash for Oncor and assume its debt and other liabilities, including funding $9.5 billion for the repayment of EFH debt. Oncor was valued at $18.4 billion before NextEra added its sweetener.

After the collapse of the Hunt group's bid, NextEra announced in July it had reached an agreement with EFH to purchase its 80.25% stake in Oncor. The other 19.75% is owned by an investor group led by Borealis Infrastructure Management and Singapore's GIC Special Investments. (See NextEra Reaches Deal for Oncor.)

NextEra says it expects to file a joint application with the PUC "soon," and that it expects the transaction to close in the first quarter of next year.

"Our proposed transaction provides Oncor with a financially strong, utility-focused owner that shares Oncor's commitment to providing customers with affordable, reliable electric delivery service and significant value and certainty for the EFH bankruptcy estate," NextEra CEO Jim Robo said in a statement.

NextEra said the deal is subject to bankruptcy court confirmation of EFH's Chapter 11 reorganization and approval by FERC and

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ERCOT NEWS

Texas PUC OKs ERCOT, SPP Studies on Lubbock Move

By Tom Kleckner

Texas regulators last week accepted a proposal from ERCOT and SPP staff on how they will coordinate their separate studies on Lubbock Power & Light's planned move to the ERCOT grid.

In a joint letter to the Public Utility Commission of Texas, Warren Lasher, ERCOT's director of system planning, and Lanny Nickell, SPP's vice president of engineering, said their studies will use "consistent input assumptions" and "rely as much as possible upon their existing study processes" (Docket No. 45633).

SPP said it will use models from its most recent Integrated Transmission Planning Near-Term (ITPNT) assessment and its 10-year ITP study. ERCOT will use models from its most recent Regional Transmission Plan and its Long-Term System Assessment.

Both RTOs will also conduct near-term reliability studies and longer-term economic studies. "Both parties will analyze their systems with and without the portion of LP&L that is part of the proposed transition," Lasher and Nickell wrote.

LP&L announced last September it planned to disconnect 430 MW of its load from SPP and join ERCOT in June 2019. An ERCOT study completed in June indicated it will cost $364 million and take 141 miles of new 345-kV rights of way to incorporate LP&L into ERCOT. (See "LP&L Integration Could Unlock More Panhandle Wind Energy," *ERCOT Board of Directors Briefs*.)

At a meeting Thursday, PUC Chair Donna Nelson said she agreed with the grid operators' approach, but she expressed concern over who would pay for the studies. "Either LP&L should fund the studies, or we should leave the issue open pending the outcome of the studies," Nelson said. "I don't think it's fair for the ratepayers in ERCOT to pay for that study."

ERCOT and SPP said they had not come to a conclusion on funding the studies, but they would discuss with the commission "the appropriate allocation of the costs."

ERCOT said it could complete its assessments before the end of the year, while SPP said it would complete its 2017 ITP10 in January and the 2017 ITPNT in April.

The grid operators said they would be unable to provide two pieces of information that Nelson requested in a July memo. (See *PUCT Asks ERCOT, SPP to Coordinate on Lubbock P&L Move*.)

Lasher and Nickell wrote their staff does not have "the expertise or the necessary data" to determine the cost and reliability impacts as separated by customer class. They also deferred to LP&L "to describe measures necessary to ensure that there will be no commingling of electrical energy from the two regions as a result of the proposed transfer."

At the same time, LP&L is conducting its own study. The utility's attorney, Chris Brewster, asked the PUC to request ERCOT and SPP disclose their assumptions "to ensure we're talking about the same things." LP&L said it had had discussions with ERCOT, but not with SPP, and questioned the latter's "scheduling constraints."

"I don't know what their scheduling constraints are, but they have a lot of employees. They have a lot of smart employees," Nelson said, pointing out Nickell and SPP attorney Sam Loudenslager's presence in the audience. "It's in their best interest that ratepayers don't end up paying for being unfairly advantaged when Lubbock leaves."

Any PUC rulemakings will wait until the results are all in next year.

"We want to make sure we can get it right," Nelson said. "We have people concerned about costs within the SPP system, and we have people concerned about costs in the ERCOT system. Clearly, we ought to be concerned about that."

Texas PUC Expresses Doubts over NextEra-Oncor Deal

Continued from page 7

the Texas commission, as well as "other customary conditions and approvals."

NextEra shares gained $4.72 from the beginning of last week, closing at $128.03/share Thursday.

The Hunt group remains unfazed by NextEra's progress, with spokesperson Jeanne Phillips saying Hunt "will continue to work with all stakeholders to develop a Texas-based solution for the purchase of Oncor."

EFH has been struggling to emerge from bankruptcy for more than two years now. It has proposed to sell Luminant and TXU to senior creditors owed $24.4 billion. Another hearing is scheduled in bankruptcy court next Monday.

ERCOT NEWS

ERCOT Finds No Alternatives to Greens Bayou; RMR Rule Changes Advance

By Tom Kleckner

ERCOT will continue its reliability-must-run agreement with NRG Energy's Greens Bayou Unit 5 after a solicitation produced no viable alternatives.

The Texas grid operator had solicited proposals for must-run alternatives (MRAs) after it entered an RMR contract with NRG Texas Power for its Houston-area unit, a 371-MW gas-fired plant, on June 2. (See *ERCOT Seeks Alternatives to Houston-Area RMR Unit*.) The contract is projected to cost the market $60 million.

ERCOT said the proposed MRAs it received by the Aug. 24 deadline would not "adequately meet the reliability need served by the Greens Bayou 5 unit." The ISO received eight offers from four qualified scheduling entities (QSEs) with a combined capacity of 385.9 MW for most of the contract months, but it said some of those offers did not qualify as eligible MRA resources and the others did not provide an "acceptable solution to the reliability concern" necessary to replace Greens Bayou.

The Greens Bayou RMR agreement addresses reliability concerns on a Houston-area transmission line. Under the agreement, the unit will remain available during summer peak demand periods through June 2018 to support system reliability under certain critical operating conditions.

ERCOT has said the $590 million Houston Import Project, scheduled to be completed by summer 2018, will solve the reliability concern.

RMR Rule Changes Proposed

Meanwhile, the Protocol Revision Subcommittee last week advanced three nodal protocol revision requests (NPRRs) related to ERCOT's RMR procedures. They will be taken up next week by the Technical Advisory Committee, which in July rejected an NRG request to allow the economic dispatch of RMR units. (See "Pricing Change on RMR Units Rejected, Appealed to ERCOT Board," *ERCOT Technical Advisory Committee Briefs*.)

- NPRR788 modifies the RMR planning studies to include forecasted peak loads and introduces a new requirement that a potential RMR unit must have "a meaningful impact on the expected transmission overload" to be considered for an agreement.
- NPRR795 creates a mechanism to refund capital expenditures funded by ERCOT under an RMR agreement, if the agreement is terminated. The refund would be based on the expenditures' depreciated book value if the resource returns to commercial operations; otherwise, it would be based on the salvage value.
- NPRR793 would clarify the reliability unit commitment process to ensure RMR units are not accidentally committed as a reliability unit before other resources. The revision request adds several responsibilities for RMR unit owners, revises RMR formulas and adds further clarifications.

Luminant, Calpine Notices

ERCOT, which already has more than 81,000 MW of capacity to meet the fall and winter's expected peak demand of less than 59,000 MW, recently got news of an additional resource.

Luminant notified ERCOT on Sept. 14 that its 805-MW coal unit at Martin Lake in East Texas, which had been running only from May to late September, will now be available for year-round dispatch. The status change is effective Oct. 1.

The Texas grid operator has also reviewed Calpine's notice that it would be suspending operations at its 400-MW, gas-fired Clear Lake Power Plant and determined the five steam and gas turbines are needed to support transmission system reliability. ERCOT will issue a final determination by Oct. 10.

ISO-NE NEWS

ISO-NE Outlines Keene Road Tx Upgrade Study

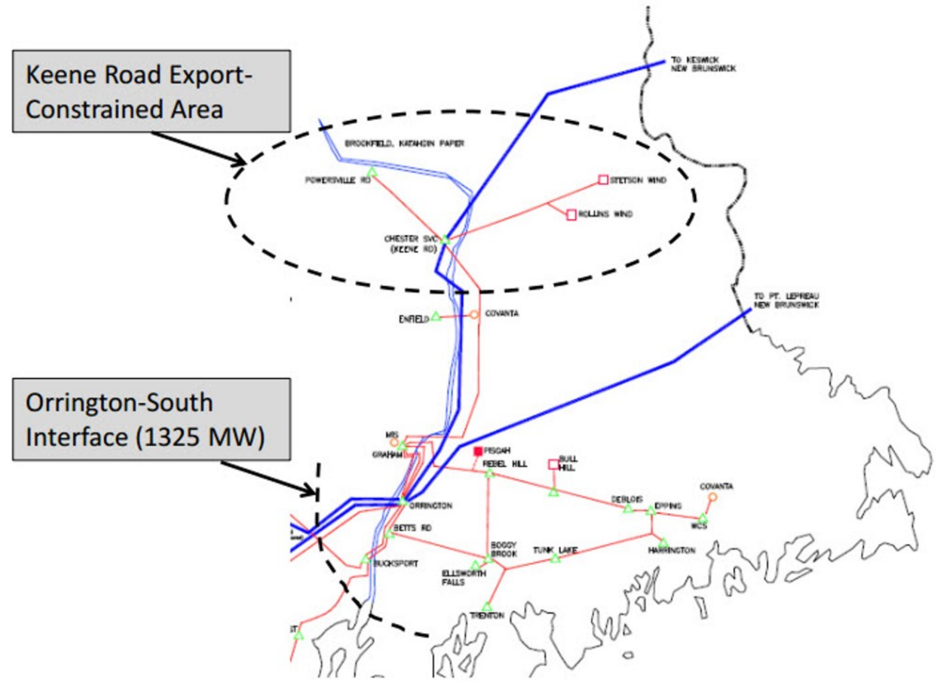
WESTBOROUGH, Mass. — ISO-NE planners last week outlined the scope of a needs analysis that will determine whether the RTO will approve transmission upgrades to accommodate wind development in the Keene Road area in Maine.

An economic study found that the area could qualify for market efficiency transmission upgrades (METUs) — projects designed to reduce the total production cost to supply system load.

At Wednesday's Planning Advisory Committee meeting, planners said the needs assessment will simulate production costs with the Keene Road export limit modeled at the existing 165-MW limit and three higher limits that top out at 255 MW.

The modeling will provide results for 2020, the projected in-service date for the upgrades, as well as 2025 and 2030. In addition to production costs, the simulations will predict metrics such as congestion, emissions and LMPs at several locations.

Draft results are expected to be brought to the PAC for stakeholder discussion by November, with final results posted in December. If the results show the upgrades qualify as METUs, the RTO could decide to issue a competitive solicitation.



Detail of Keene Road export-constrained area | *ISO-NE*

A draft study in 2015 found that increasing the export limit to 225 MW could save $1.4 million to $5.7 million in production costs annually by allowing additional wind development in the area and displacing more expensive hydropower. (See "Draft Study Shows Greater Wind Penetration Benefits," *ISO-NE Planning Advisory Committee Briefs*.)

— William Opalka

MISO NEWS

Brattle Endorses MISO Forward Auction Proposal, Designs Demand Curve

By Amanda Durish Cook

The Brattle Group last week endorsed MISO's proposed Competitive Retail Solution, conditioned on the RTO adopting a wider demand curve that the consulting firm developed.

Brattle's demand curve, revealed in its latest analysis of MISO's proposed forward auction, is capped at 140% of the net cost of new entry (CONE). The foot of the curve lands at 115% of MISO's planning reserve margin requirement and a $0 net CONE.

Brattle said the net CONE cap is "slightly above" MISO's requested $195/MW-day figure for Zones 4 and 7 and the $185/MW-day price elsewhere.

Brattle analyst Samuel Newell said the analysis concluded that MISO's separate forward auction solution will address reliability concerns while inviting merchant investment. It projects volatility will be reduced by 6 to 15% compared to a status quo case Brattle researched.

Volatility

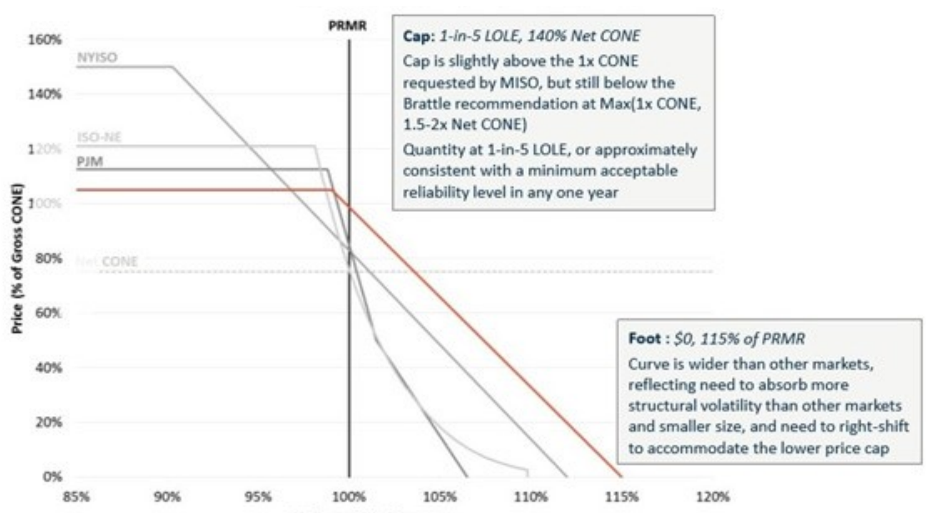
Newell said the wider curve Brattle recommends seeks to "absorb more structural volatility than other markets," and the curve's shift to the right is needed to accommodate a lower CONE price cap than what's in use at other RTOs. Brattle said the curve "allows some shortage at high prices."

He said Brattle has recommended caps ranging from 1.5 times to two times net CONE in other regions. The recommended sloped demand curve is less steep than other regions' and extends farther to the right.

"A reason to have a higher cap is to put more money in the market, and it helps protect against the risk of under-procurement if you've underestimated CONE," Newell said. "Yes, the pricing is going to be volatile because of all that uncertainty that goes into the system. But as long as you have enough money built into the curve and the curve is shifted far enough right, you will attract enough megawatts."

Brattle's analysis predicts the new capacity structure would meet or exceed the one-day-in-10-years loss-of-load expectation (LOLE) and attract an additional 1,800 MW of merchant supply. Brattle also said the forward auction on average is predicted to clear an extra 120 MW. The analysis results will be included as testimony in MISO's FERC filing to win approval of the forward auction.

The firm also said use of the sloped demand curve in the long run should result in average forward prices that spur merchants to build; however, Newell said the analysis didn't forecast prices under the new auction construct. "The reason we're here isn't to forecast prices. It's to address the widespread belief — that I think is right — that current prices won't support merchant supply meeting need."



The candidate demand curve is "tuned" to achieve a one-in-10 LOLE on behalf of competitive retail customers, though other demand curves achieving one-in-10 could also be developed. | *The Brattle Group*

Status Quo Falls Short

Brattle did find that in the long run, use of the demand curve under the forward design reduces the instances of auction prices clearing at the demand curve cap to 39% of years. When Brattle tested a status quo scenario in retail-choice zones, clearing at the demand curve cap amount happens 65% of the time in Zone 4 and 67% of the time in Zone 7. Brattle maintains some capacity prices clearing at the cap is needed to keep average clearing prices closer to net CONE.

Newell said Brattle tracked enough merchant supply to assume a one-in-10 standard with the curve, but MISO can also assume its utilities own supply averaging 3% more than their individual requirements. Brattle found that continuing with the status quo would result in MISO falling 891 MW short of its planning reserve margin requirement in the long term in MISO North. The status quo auction, Brattle said, also results long-term in a one-in-5.2 LOLE "with frequent severe shortage" events and a majority of auction offers clearing at the price cap.

Bill Booth of the Mississippi Public Service Commission asked if Brattle did its own analysis of MISO's CONE value. Newell said his firm did not test the accuracy of MISO's net CONE. But even if MISO does revise its CONE values, Newell said, results wouldn't be affected much, as Brattle's higher, 1.4-times CONE cap "mitigates reliability risk of administrative error in estimating net CONE."

"This aspect is exactly the same as the one we went through for PJM and New England. This aspect of it is very established ground," Newell said.

Newell said the bigger issue is whether Brattle's assumptions regarding cap and foot values and utilities' ownership is correct. Brattle analyst David Oates said a lot of the modeling, including the Monte Carlo-style analysis, is similar to what was done in PJM and ISO-NE.

MISO South

Indianapolis Power and Light's Ted Leffler

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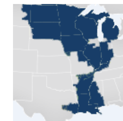
MISO NEWS



MISO: Stakeholders Behind 2nd Queue Reform Attempt

By Amanda Durish Cook

CARMEL, Ind. — MISO will file a revised set of interconnection queue changes with FERC on Oct. 21, and this time it says it has "overwhelming" stakeholder support for the changes.

In its second attempt at a queue reform filing, MISO proposed that the revised M2 milestone become a flat charge of $4,000/MW of new capacity instead of the earlier $5,000/MW. The M3 and M4 fees would total 10% and 20% of any upgrade costs, respectively. MISO would settle any over- or underpayment after it completed a final facility study. (See "MISO Tries to Please FERC with Second Attempt at Queue Reform," *MISO Planning Advisory Committee Briefs*.)

All but seven of the 27 members that provided feedback this month supported the three milestone payments. Nearly all members supported total milestone payments being applied to the generator interconnection agreement's initial payment.

The majority agreed that a project should be able to withdraw penalty-free if a facility study shows costs 25% or $10,000/MW more than the system impact study's projection. Stakeholders were about evenly split, however, on whether MISO should allow interconnection customers to decrease the number of megawatts they signed up for by 10% at the second decision point of the queue, where projects that withdraw before the first 220 days of the queue can be refunded their entire M3 payment. MISO is proposing 10% megawatt decrease options at both decision point two and the approximately 140-day decision point one, where withdrawing projects are credited their entire M2 milestone payment.

Of the 27 members who responded to MISO, 20 said they generally supported the revised queue reform proposal, five said they did not and two abstained from offering an opinion.

FERC rejected MISO's first proposal in March, saying the RTO failed to consider other factors when it blamed the queue bottleneck on "speculative" projects. The commission also said MISO's proposed milestone payments created a "barrier to entry" (ER16-675).

At last week's Planning Advisory Committee meeting, MISO Director of Interconnection and Planning Tim Aliff said the RTO is responding to FERC's order by adding more requirements for itself and its transmission owners to lessen the burden on the interconnection customer.

Tim Aliff | © *RTO Insider*

At this month's MISO Board of Directors meeting in St. Paul, Minn., MISO Vice President of System Planning and Seams Coordination Jennifer Curran said the RTO is hoping to build more certainty into the process and reduce restudies and the amount of time it takes for projects to clear the queue. "It's currently a two- to three-year process and is challenged by restudies," she said. "We think we've struck a nice balance between all of the interested parties here."

If approved by FERC, queue changes will take effect in January. Although the new queue rules have not been approved, MISO has nevertheless moved ahead with the transition, which will be fully completed after February 2017's batch of interconnection entrants.

Brattle Endorses MISO Forward Auction Proposal, Designs Demand Curve

Continued from page 11

asked why MISO South was again left out of the analysis, as it was in a Brattle review released in July. (See *MISO Backs Forward Auction Plan, Rejects Prompt Proposal*.)

Brattle maintained the omission of MISO South was inconsequential, saying the 876 MW available for imports from the South is covered in varying megawatt amounts that utilities offer in the Monte Carlo analysis.

The company also modeled capacity import limits but not export limits and assumed utilities have a preference to build their own capacity instead of purchasing it from other utilities.

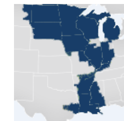
Zone 2 in Wisconsin and Michigan, which holds a small amount of participating demand, was initially included in the analysis, but Brattle found that it didn't meet MISO's materiality threshold.

In response to a question from Madison Gas and Electric's Megan Wisersky, Newell said Zone 2 was initially included because it contains some competitive load. But MISO's Mike Robinson said the inclusion was a relic of the RTO's earlier work with Brattle and could be omitted altogether.

"It would be nice not to see that ever," Wisersky joked.

Newell said MISO will use this week to gather stakeholder feedback before announcing the final demand curve shape at the Resource Adequacy Subcommittee meeting Oct. 6. He added that additional curves suggested by stakeholders that achieve the one-in-10 standard could be tested.

MISO News



MISO Stakeholders Propose Changes to Market Efficiency Cost Allocation Process

By Amanda Durish Cook

CARMEL, Ind. — Stakeholders support MISO's push to revise its cost allocation process for market efficiency projects (MEPs), but their suggested approaches are a mixed bag.

By the end of this year, MISO will release a conceptual proposal that may expand its market efficiency voltage threshold to include sub-345-kV economic projects. The proposal may also revise the current MEP cost allocation: 80% of costs to benefiting local resource zones and 20% footprint-wide. The RTO said it is considering assigning 100% of MEPs to local resource zones.

MISO plans to file the revised cost allocation rules by 2018, when Entergy's MISO integration transition period — which limits cost sharing in MISO South — expires.

Members' proposed changes were presented at the Sept. 20 special meeting of the Regional Expansion Criteria and Benefits Working Group.

"I'll be honest: My team doesn't look for solutions that aren't 345 kV. There's a very limited amount of developers that will go for projects under 345 kV."

Kamran Ali, American Electric Power

Remove Threshold?

American Electric Power Director of Transmission Planning Kamran Ali said his company believes the 345-kV threshold should be eliminated so transmission owners begin to look for the most efficient transmission projects. "I'll be honest: My team doesn't look for solutions that aren't 345 kV. There's a very limited amount of developers that will go for projects under 345 kV," Ali said.

He pointed to three projects ranging from 115 to 138 kV in Indiana and Louisiana, identified in MISO's 2016 Transmission Expansion Plan, whose benefits are expected to extend across multiple local resource zones.

Attorney Jim Dauphinais, on behalf of Illinois Industrial Energy Consumers and the Louisiana Energy Users Group, said MISO should lower its market efficiency voltage threshold to 100 kV, or at least down to 230 kV.

Dauphinais said MISO's current allocation process doesn't recognize the value sub-345-kV economic transmission projects can provide outside of their local transmission pricing zone. He pointed to a 2015 Entergy study that found the 230-kV Louisiana Economic Transmission Project has economic benefits that bleed over both transmission pricing zone and local resource zone boundaries.

Cost Allocation Below 345 kV

Currently, costs of economic projects below 345 kV are allocated only to their local transmission pricing zones unless multiple MISO members in different zones sponsor construction.

The Organization of MISO States said it could not support systemwide cost allocation of a sub-345-kV economic project without evidence from MISO that such projects can provide footprint-wide benefits.

Mississippi Public Service Commission staff counsel David Carr, representing OMS, said formulating a methodology for regionally allocating costs of sub-345-kV interregional projects is "of the essence" because of FERC's April ruling in a challenge by Northern Indiana Public Service Co. The commission ordered MISO to remove its 345-kV threshold on interregional projects with PJM. (See *MISO, PJM Working to Comply with NIPSCO Order*.)

The MISO Transmission Owners sector said it does not have a position on whether MISO should lower the voltage requirement. However, the sector opposes a postage stamp cost allocation for projects below 345 kV, which would assess all regional transmission service customers a uniform rate based on the combined costs of all transmission facilities in the region.

Throw Out Postage Stamp?

ITC Holdings' David Grover said postage stamp pricing is still appropriate for projects 345 kV and above and said if any change is considered, the footprint-wide postage stamp allocation should probably be raised beyond the current 20%. "Identifying beneficiaries with pinpoint accuracy is not realistic … [and] fraught with uncertainty," Grover said. "I would argue that all networked 345-kV lines … have multiple benefits."

Other stakeholders contend that MISO's hourglass shape, with its constraint between MISO North to MISO South, precludes an equitable systemwide postage stamp rate.

NIPSCO engineer Miles Taylor said MISO should implement a more targeted benefit and cost allocation determination for lower-voltage projects.

Taylor said MISO should eliminate postage stamp rates and local resource zone cost allocation and implement cost allocation based on benefiting transmission pricing zones.

Dauphinais said MISO should replace all postage stamp rates with a 100% adjusted production cost allocation. He said MISO should allocate 100% of adjusted production costs at the transmission pricing zone instead of the current "coarser" local resource zone level. "We're not going for perfection, but we need to have something at least in the ballpark. We want to make sure costs are assigned appropriately as we can," Dauphinais said.

Ameren's Dennis Kramer said wrestling with cost allocation is "endemic," noting that MISO has been tweaking cost allocation of transmission projects for a decade. "There's never going to be certainty because there's assumptions and projections associated with this," Kramer said.

Ameren recommended MISO "have a single MEP process that can be used throughout the entire MISO footprint." However, Ameren said MISO's current multi-value projects > MEPs > baseline reliability projects hierarchy is a "cornerstone of MISO's Order 1000 compliance and should not be significantly altered."

Ameren said a voltage threshold reduction should be investigated as part of an overall

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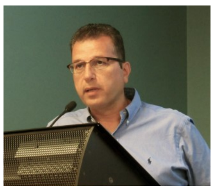
MISO NEWS

Planning Advisory Committee Briefs

MTEP 16 Report Up; MTEP 17 Forecasts Almost Finished

CARMEL, Ind. — MISO posted the second draft of the 2016 Transmission Expansion Plan report last week, complete except for the executive summary and Appendix A2's cost allocation explanation.



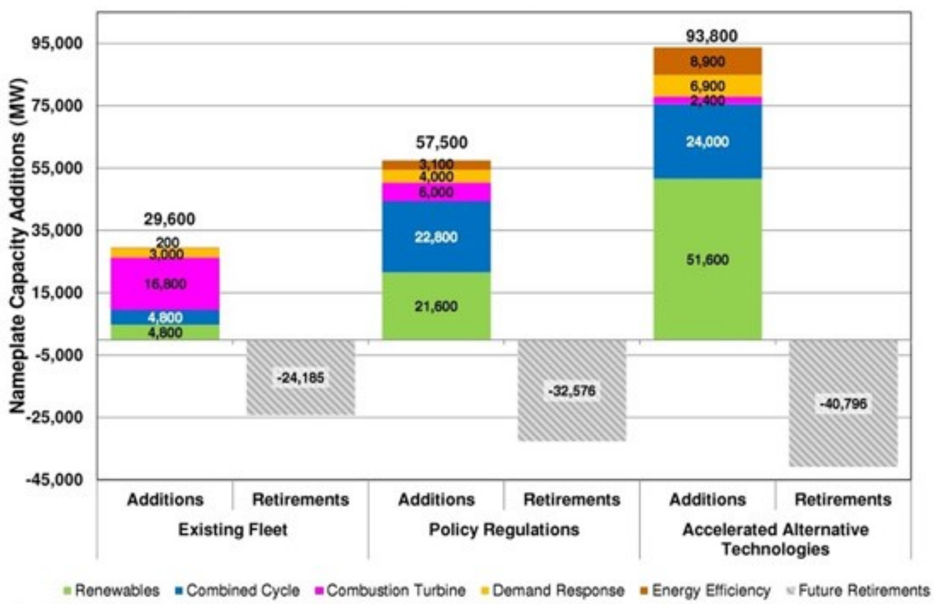
MISO's **Omar Hellalat** told the Planning Advisory Committee last week that stakeholder feedback forms, which will be delivered to the Board of Directors, are due Oct. 3. The PAC will vote on approving the report Oct. 19. (See *MTEP 16 Proposes 394 Projects at $2.8 Billion*.)

"We're not voting on the projects; we're voting on the process. Did we follow it?" PAC Chair Bob McKee explained.

Meanwhile, MISO members have until Oct. 12 to respond to the MTEP 17 proposed futures, Senior Transmission Planning Engineer Matt Ellis said.

Ellis said the MTEP 17 forecast mirrors trends that showed up in MTEP 16, although MTEP 17 projects higher natural gas consumption. Ellis also said MISO is forecasting 25 GW of retirements by 2031 in the "existing fleet" scenario, 33 GW of retirements in a "policy regulations" future and 41 GW of retirements in the "accelerated alternative technologies" future.

The RTO is forecasting nameplate capacity additions of 30 GW, 58 GW and 94 GW by 2031, respectively.



MTEP 17 includes three scenarios for how the generation fleet will change by 2031. | *MISO*

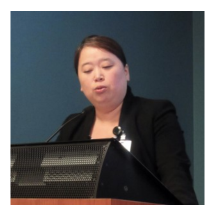
The study will consider wind resource additions of 2.4 to 30 GW and solar additions of 1.6 to 14.4 GW. MISO also expects peak demand of 127 GW in 2016, rising to between 131 and 145 GW by 2031.

McKee asked what drove the renewables predictions. Ellis said MISO used information from projects in the interconnection queue and a study from renewable firm Vibrant Clean Energy that was commissioned by the RTO. (See "MTEP 17 Futures Process Enters Stakeholder Inspection," *MISO Planning Advisory Committee Briefs*.)

Feedback on the forecasts should be emailed to mtepfutures@misoenergy.org.

Long-Term Overlay Study Scoped; MISO Asks for More Responses

MISO has issued a draft scope for its Regional Transmission Overlay Study. The study will identify needs to develop a regional transmission plan and identify candidate projects by 2019 using the three futures created for MTEP 17. (See "MTEP 17 Futures Finalized," *MISO Planning Advisory Committee Briefs*.)



"The purpose of the study is really to get our arms around what the system needs," said **Lynn Hecker**, MISO manager of expansion planning.

MISO has already received a first round of comments on the study scope, with stakeholders raising many issues, including asking the RTO to incorporate non-transmission alternatives and encouraging it to work with

Continued on page 15

MISO Stakeholders Propose Changes to Market Efficiency Cost Allocation Process

Continued from page 13

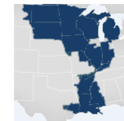
re-examination of the MEP process. The company said resource zones are probably too large for determining cost allocation while transmission pricing zones may be too small and could be combined.

Ameren also said MISO should determine whether stakeholders want additional benefit metrics — such as reduced capacity costs due to reduced peak hour transmission losses, reduced operating reserves and avoided reliability projects — included in market efficiency benefit calculations.

Kramer said Ameren has a problem if MISO re-examines costs that have already been allocated. "An [adjusted production cost] benefit metric will almost always result in winners and losers depending upon which side of the constraint the stakeholder is located," Ameren said. Kramer also said low-cost MEPs are "probably not worth the time and expense" of MISO's competitive bidding process.

Andrew Siebenaler, a planning engineer with Xcel Energy, said MISO's modeling assumptions on MEPs must be carefully reviewed. Siebenaler also said inexpensive, lower-voltage projects carry less capacity, "making them more sensitive to changes in assumptions."

MISO News



FERC: Further Compliance Filings for Entergy, MISO

FERC Accepts Entergy Compliance Filing, with Conditions

FERC accepted Entergy's compliance filing responding to a December ruling that found fault with the company's accounting in its fourth annual bandwidth filing (ER10-1350). (See *FERC Rules Against Entergy over 'Bandwidth' Accounting*.)

The commission, however, found that it had "inadvertently" not included in its December order a requirement to calculate interest on refunds related to bandwidth payments. It asked Entergy to submit another compliance filing that recalculates interest, eliminates any refunds related to the sale/leaseback of its Waterford 3 nuclear plant and removes securitized asset accumulated deferred income tax (ADIT) and contra-securitized asset ADIT from the bandwidth calculation.

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

MISO Compliance Filings Still Contain Errors

FERC yet again sent proposed Tariff revisions related to demand response back to MISO for further clarification in two orders.

The first order addresses MISO's Order 745 compliance filings addressing contradictory language in Tariff revisions that laid out a new cost allocation methodology for compensating DR resources (ER12-1266). FERC found that the RTO mostly complied with its directive to clarify its Tariff, but the commission found yet more inconsistencies within and between sections of its Tariff regarding compensation across zones, cost allocation between day-ahead and real-time market participants and the effective date for certain provisions.

FERC also found discrepancies between MISO's compliance filings regarding Order 719 (ER12-1265). For example, the commission found that MISO used "megawatts" to express maximum daily regulation deployment in its August 2012 filing and "megawatt-hours" in its September 2013 filing. FERC also found that the RTO did not differentiate between consumption baselines for DR resources providing regulating reserves and those providing contingency reserves.

The commission directed MISO to submit compliance filings addressing its concerns in both dockets within 30 days.

— Tom Kleckner

Planning Advisory Committee Briefs

Continued from page 14

the Organization of MISO States. Some would like to create another stakeholder group to oversee the overlay.

Hecker, who called the comments "very insightful," said that MISO has reached out to individual states but not OMS. Hecker said further scope development will be handled by MISO's Economic Planning Users Group.

Adam McKinnie, chief utility economist of the Missouri Public Service Commission, said OMS would have appreciated direct discussion from MISO on possible overlay needs.

Hwikwon Ham, a staffer with the Minnesota Public Utilities Commission, said it is imperative that MISO continue to reach out to state regulators with scope information.

Stakeholders also asked to what degree the Clean Power Plan would influence the overlay. Ham said use of the CPP in the overlay should not be considered "controversial" because MISO's resource mix is changing regardless of whether the rule survives.

In February, the Supreme Court stayed the plan pending resolution of legal challenges. Oral arguments are scheduled before the D.C. Circuit Court of Appeals for Tuesday.

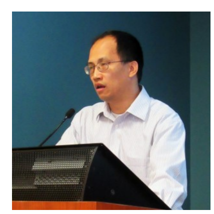
Hecker said the MTEP 17 futures will be flexible enough regardless of whether the CPP "comes back to life."

MISO will also revisit the overlay's future scenarios when MTEP 18 futures are developed to determine if overlay assumptions need to be refreshed.

Another round of stakeholder input on the overlay scope is due Oct. 5. MISO plans to release a finalized scope at the Oct. 19 PAC meeting and schedule the first technical study meeting in November.

MISO to Update Long-Term Planning BPM

MISO is planning some housekeeping on Business Practices Manual 020, which governs the RTO's long-term planning process.



Zheng Zhou, an economic studies engineer, said the changes will only be a clean-up to reflect long-term planning practices already in place. "This section hasn't been updated for quite some time, and we understand that this BPM is important to our stakeholders," Zhou said.

Updates include adding to the MTEP futures development MISO's 2015 process reforms, which allowed futures to be reused across MTEPs, and a more detailed inclusion of MISO's seven-step value-based planning process, which identifies and tests transmission fixes.

MISO hopes to file the changes by early 2017. Stakeholder input on the updates is due Oct. 19.

— Amanda Durish Cook

MISO News

FERC Upholds MISO's White Pine, Escanaba Refunds

FERC said MISO can continue doling out refunds to Wisconsin utilities, upholding the RTO's new cost allocation methodology for three system support resource power plants in Michigan's Upper Peninsula (EL14-34, *et al.*).

The commission's Sept. 22 order determined that MISO's plan to refund load-serving entities overcharged under the old methodology was satisfactory, rejecting rehearing requests that argued the commission did not have the power to order refunds.

The order stems from 2014, when FERC ordered MISO to scrap its SSR cost allocation on a *pro rata* basis to all LSEs in the American Transmission Co. service territory and instead assign costs to LSEs that required the White Pine, Escanaba and Presque Isle plants for reliability. (See *FERC Upends MISO's SSR Cost Allocation Practice*.)

FERC accepted MISO's revised SSR cost allocation methodology in early May, and the RTO submitted its refund reports in June. The RTO will make the LSEs whole in 14 monthly installments, which began in July.

However, the commission instructed MISO to suspend refunds for the Presque Isle SSR costs until it reaches a decision on an administrative law judge's finding that Michigan ratepayers were overcharged by Wisconsin Electric Power Co. (ER14-1242-006, *et al.*). (See *ATC Plan Could Eliminate White Pine SSR; Refunds Coming on Presque Isle?*) MISO will then have to submit another refund report for the plant within 45 days of the commission's decision.

FERC also directed MISO to provide "complete, un-redacted" copies of the refund reports to parties that have entered nondisclosure agreements.

— Amanda Durish Cook

Presque Isle | *WEPCo*

FERC Rejects Occidental Rehearing Request on PURPA Decision

FERC said last week it remains unconvinced that MISO's plan to integrate qualifying facilities into Entergy's footprint would violate Occidental Chemical's rights under the Public Utility Regulatory Policies Act, denying the company's request for rehearing of its April order (EL13-41-001).

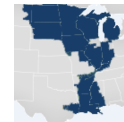
MISO's QF plan, implemented when Entergy first joined the RTO, included two options for QF participation, a "hybrid" option and a behind-the-meter option. Occidental claimed the commission failed to address its argument that QFs participating under the behind-the-meter option would have to give up their PURPA rights. Much of FERC's original order focused on Occidental's arguments against the hybrid option. (See *FERC Denies Occidental's PURPA Complaints*.)

In its original order, "the commission discussed … why requiring a behind-the-meter QF to be reflected in MISO's commercial model as an Entergy asset for purposes of MISO market participation does not unduly discriminate against QFs," FERC said. "Occidental has not elaborated why the commission erred in its rejection of Occidental's arguments that the behind-the-meter option is unduly discriminatory."

FERC concluded that QFs "could participate in the MISO market while continuing to exercise their rights pursuant to PURPA, and that MISO does not need to modify its Tariff."

— Amanda Durish Cook

MISO NEWS



FERC Finds No Significant Problems in Ameren Rate Filing

By Amanda Durish Cook

FERC has brushed aside a complaint brought forward by two companies about Ameren Illinois' annual informational formula rate update and true-up (ER16-1169).

In April, Southwestern Electric Cooperative and Southern Illinois Power Cooperative challenged the $214.4 million revenue requirement rate filing on several fronts. Although FERC agreed with a few points the cooperatives raised, the complaint was dismissed.

FERC ordered Ameren to change how it accounts for contributions in aid of construction. The commission also said it is "improper for Ameren Illinois' [net operating loss carryforward] to affect Ameren Illinois' income tax allowance because the tax is deferred, not avoided." The commission ordered Ameren to include net operating loss carryforward in its rate base to "reflect the fact that the company is unable to take full advantage of its favorable tax timing difference."

The challenge also caused Ameren to agree with the complainants that it should exclude accrued tax debt, merger costs debt integration, regulatory asset amortization and regulatory liabilities for allowance for funds used during construction from its 2016 true-up.

FERC, however, denied other areas of the challenge:

- The complainants said Ameren is allocating solely to transmission certain costs that involve both transmission and distribution. FERC said that while "the naming of certain accounts could be misleading," the accounts were only related to transmission costs.
- The two cooperatives said Ameren should not be allocating franchise fees to customers; Ameren responded that because the franchise fees allow transmission construction, they should be included in transmission rates. FERC said Ameren is allowed to recover franchise fees and said the particular challenge "amounts to a collateral attack on the filed rate."
- The complainants alleged Ameren's formula rate was improperly related to its generation and distribution functions and asked for "a line-by-line review of specific entries to eliminate generation or distribution-related items." FERC said that asking for cost to be "functionalized on a direct assignment basis instead of on the basis of an allocation ratio" amounted to challenging the formula rate itself and could only be addressed in a separate filing.
- The cooperatives accused Ameren of including costs relating to retail distribution and customer services into the general and intangible plant cost allocation to transmission, which increased from $20.3 million in 2008 to $63.8 million in 2016. FERC said it found "no reason to conclude that Ameren Illinois is not properly classifying the challenged items."
- The complainants questioned the 117% jump in Ameren's wages and salaries allocation over six years. FERC said the increase was reasonable because Ameren Illinois was using more transmission labor.

MISO NEWS

MISO not Allowed to Allocate Lake Erie PARs Costs to PJM and NYISO

By Amanda Durish Cook

A proposal by MISO and ITC Holdings to allocate the costs of phase angle regulating transformers (PARs) to entities outside of MISO is not just and reasonable, FERC ruled last week.

The commission's Sept. 22 order upheld Administrative Law Judge Steven Sterner's 2012 decision prohibiting MISO and ITC from allocating the costs of ITC's two 700-MVA PARs on the Michigan-Ontario border to NYISO and PJM (ER11- 1844-001, ER11-1844-002). The commission also denied as moot requests by several parties for rehearing.

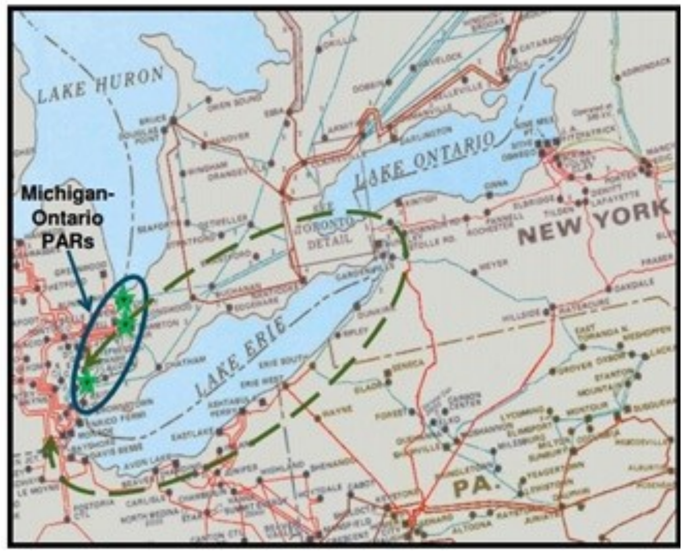
Failure to Show Benefit

FERC said MISO and ITC "failed to show that NYISO or PJM will benefit from the operation of the ITC PARs." The commission noted that two NYISO and PJM witnesses testified that the two grid operators could "actually be harmed by the planned operation of the ITC PARs."

"For example, a reduction in counterclockwise loop flow that may benefit MISO might, at the same time, harm NYISO if both transmission systems are experiencing congestion on transmission facilities that are affected by loop flow," FERC wrote.

MISO and ITC proposed allocating 49.6% of the PARs cost to MISO, 19.5% to PJM and 30.9% to NYISO, based on each region's contribution to the loop flows that would occur over the Michigan-Ontario interface without the PARs. Unscheduled loop flows around the Lake Erie region have been a problem since the late 1990s.

FERC ordered MISO and ITC to refund, with interest, all amounts collected pursuant to their Oct. 20, 2010, filing in excess of rates in effect prior to Jan. 1, 2011. MISO also has 30 days to revise parts of its Tariff that pertain to the cost allocation of PARs.



MISO

Reversal

FERC, however, reversed Sterner's ruling that MISO and ITC were precluded from unilaterally filing proposed solutions with the commission. "While the commission has made clear its preference that interconnected utilities strive to resolve loop flow-related issues among themselves rather than resort to unilaterally filing proposed solutions with the commission, a public utility is legally permitted to make a unilateral filing to address loop flow," FERC said.

PJM opposed the PAR cost allocation, saying that ITC's two PARs replaced a single failed 800-MVA PAR that was "planned, developed and placed into service to meet local system needs." NYISO objected to paying cost allocation for the ITC PARs because they "were not developed pursuant to a commission-approved regional planning process."

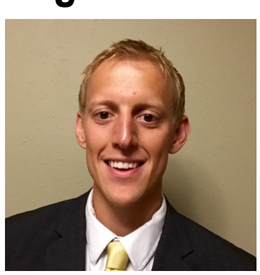
ITC and MISO's case for allocating the costs rested on Lake Erie's loop flows no longer presenting a problem for PJM and NYISO. In a 2014 report, MISO, PJM and Ontario's Independent Electricity System Operator (IESO) found that all five of the Lake Erie PARs were able to keep actual flows within 200 MW of scheduled flows most of the time.

Plans on Hold

After completing a yearlong observation of the ITC PARs and three other PARs at the Michigan-Ontario border in 2013, PJM and MISO incorporated the PARs into their market-to-market process on July 28. For now, PJM has put on hold plans to use the PARs for congestion management.

Former Wisconsin PSC Engineer Marcus Hawkins Joins OMS Staff

Marcus Hawkins, a senior engineer in the Division of Regional Energy Markets at the Wisconsin Public Service Commission, has joined the Organization of MISO States as its director of member services and advocacy. Hawkins will assist OMS Executive Director Tanya Paslawski.



Hawkins

Hawkins, who has a bachelor's in nuclear engineering and a master's in mechanical engineering from the University of Wisconsin at Madison, considers his engineering experience to be an asset in his new role.

"It's a very interesting position because it isn't all technical all the time, but it helps to have the technical background," Hawkins said. "Working at the commission was that same sort of sweet spot between the technical side and the policy side."

Hawkins said his previous position with the Wisconsin PSC afforded him multiple opportunities to work with OMS. "I hope to enhance representation of the members of OMS both at MISO and FERC, and I'm excited to get started," he said.

— Amanda Durish Cook

NYISO NEWS

NYISO Distributed Energy Resources Workshop

NYISO DER Workshop Contemplates the Grid of the Future

By William Opalka

> "It took us 12 years to add 7% of renewables, but in the next 20 years we have to add 22%."
>
> **Rana Mukerji, NYISO**

ALBANY, N.Y. — California's challenge in integrating large amounts of renewable generation is illustrated by its famous "duck curve" graph. For New York, the future looks more like a platypus.

That's how **Rana Mukerji**, NYISO's senior vice president of market structures, described the impact of large amounts of solar generation on the New York grid in the winter at the ISO's Distributed Energy Resource workshop last week.

NYISO, which released its DER Roadmap last month, held the session to open public discussion on how it will respond to the state's Reforming the Energy Vision initiative. (See *NYISO Releases Plan for Integrating DER*.)

For starters, the ISO is pursuing a modest goal of planning for the next three to five years. A conceptual market structure design will be devised next year.

The roadmap, which officials described as a guide that could change as stakeholders become engaged in the process, anticipates implementation in 2021.

New York's recently adopted Clean Energy Standard, which calls for 50% renewables by 2030, is the impetus, along with public demand for emissions-free power generation.

"We are moving very rapidly to a resource mix [that] will have intermittent resources [that] are renewable, distributed resources, and we will also have conventional generation," Mukerji said. "I do not see conventional generation disappearing anytime soon. There is some talk of 100% renewable, but I don't see conventional generation disappearing over the next 20 years."

Wind generation, currently 3% of NYISO's energy production, is projected to reach 13% by 2030.

"It took us 12 years to add 7% of renewables, but in the next 20 years we have to add 22%," Mukerji said.

He cited projections that distributed generation without subsidies will rapidly reach grid parity. The Clean Energy Standard is going to accelerate renewable energy deployment, with solar growing from its current capacity of about 700 MW.

He added that the ISO has done simulations of up to 9,000 MW of solar in New York, which presents quite a different profile of the state's demand in the morning and evening peaks.

"We will have needs for managing the ramping during the morning and the evening, so we might have to contemplate new products, like ramping products and load-following products in our market," he said.

As more distributed resources are added, it will require the ability to manage bidirectional power flows.

"It will get more challenging, but in my mind it will get more interesting, and at the end of the day it gets better efficiency and it's going to drive a cleaner, more resilient and more reliable grid," he said.

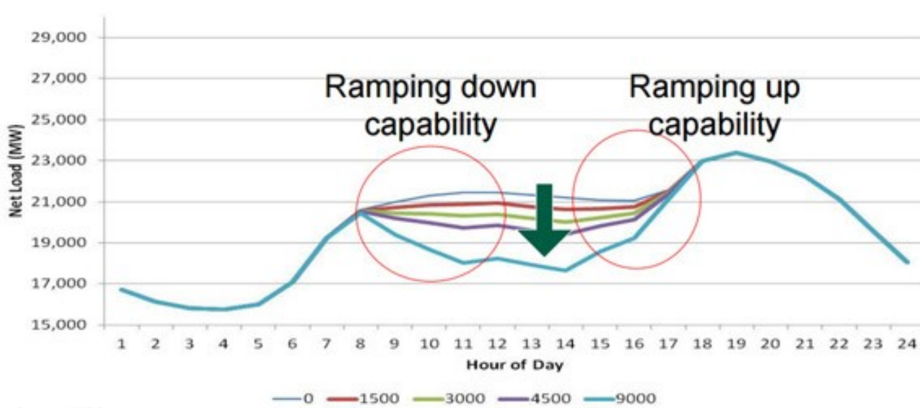
Role of NYISO

NYISO will be charged with providing a bridge between distributed generation and the central station generators.

"We have to evolve from a corps of 400 central station generators to whatever is left of the corps of 400 with the distributed system platform, which coordinates or controls the distributed resources," Mukerji said.

That's where the nexus of REV and the ISO lay, with the distributed system platform, run by the utility. The ISO will not have visibility of the generation resources beyond the substation level.

"That is where the DSP will interact the with the ISO, like a super-aggregator to participate with this animated load and the sum total of the distribute resources into the markets. That is where the interaction of the DSP and the ISO is, where the coordination between the central station generation and the distributed resources happens," he said.



The platypus curve? Levels of solar penetration on a typical New York day | *NYISO*

NYISO NEWS

NYISO Distributed Energy Resources Workshop

NYISO CEO **Brad Jones** said he is not convinced by any argument that the DER Roadmap pits the strength of a large grid against the resiliency of a small grid, as the system needs both to be robust. "Our goal is to find a way to bring both of those together to allow each of those different parts of the grid to provide efficiency for our operations and reliability for the overall grid."

Audrey Zibelman, chair of the New York Public Service Commission, said, "We want the distribution markets to be optimizing distributed energy resources and optimizing load and co-optimizing that with the wholesale market, so that way will have a two-way seamless grid that is vertically coupled, that allows us to have a system that is more reliable, more dynamic, more efficient and more environmental."

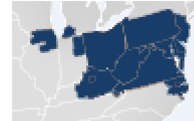
Cristin Lyons, partner at consultant ScottMadden, discussed the difficulty grid operators and utilities face in gaining visibility into the volume of distributed generation and how and when it is producing. There also are questions about whether they can be aggregated and how they will be compensated, she said. "Can you verify when they've operated? Do you even know if they are coincident with peak? Are they dispatchable? ... At the end of the day, how do all these resources get paid? I think if we're ever able to figure out the money, everything else will follow. We're not there yet."

Nick Tumilowicz, who manages the Electric Power Research Institute's DER integration effort, discussed Consolidated Edison's Brooklyn-Queens project, which is using battery storage and distributed generation to delay construction of a $1.2 billion substation. EPRI is performing a life-cost analysis. "What does it look like when we deploy battery storage in the field … to support peak demand and efficient transmission and distribution deferral?"

Kelli Joseph, director of market and regulatory affairs for NRG Energy, considered how uncertainty in the markets currently limits how different technologies could participate. "There's a lot of uncertainty … about what rate design they're going to have on the distribution side. For some projects, without a wholesale participation, they probably don't pencil out."

Mike DeSocio, NYISO's senior manager of market design, devised what he said is a simple way to look at how generation assets can be classified as distributed. "If you have an asset that's large enough to participate in the [wholesale] market today, you're not a DER. If you have an asset that's too small to participate in the market today and you think you're going to need to aggregate it to participate, that's a DER, whether it's in front of the meter or behind the meter."

PJM NEWS



PJM Grid 20/20: Focus on Distributed Energy Resources

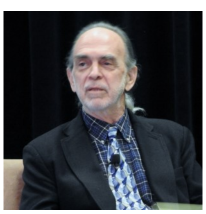
PJM Symposium: As DER Rises, Focus on Distribution System Needs

By Rory D. Sweeney

CHICAGO — The growth of distributed energy resources and behind-the-meter innovation will require upgrades to the distribution network, speakers told PJM's Grid 20/20 symposium last week.

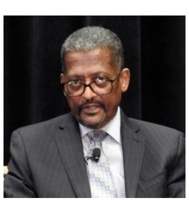
While the innovative technology driving DER was the subject of much of the daylong conference, many speakers made sure to mention the more mundane network issues as well.

Often, the distribution and transmission networks are treated "as if they're almost identical," said the symposium's keynote speaker, **Michael Caramanis**, a mechanical and systems engineering professor at Boston University. But a major advantage of the distribution network over the transmission network is that DER capabilities can allow it to sustain a much more competitive market, he said.



While distribution networks tend to experience more unusual situations on a regular basis — a condition described as "normal abnormalities" by CAISO's **Lorenzo Kristov** — they also introduce greater marginal-cost granularity across the system, Caramanis said. Using distribution locational marginal pricing (DLMP), that granularity can be harnessed.

"That granularity, if it's projected into management of distributed energy resource behavior … may affect the aggregate demand [seen] at the transmission and distribution interface," he said.



"Right now, we're in a period of evolution," explained **David Owens**, the Edison Electric Institute's executive vice president for business operations group and regulatory affairs. "The goal is to try to move more toward a market. … We have peer-to-peer transaction, but somebody's got to see all of [the transactions]. Somebody's got to provide that platform. Somebody's got to manage it. There's got to be visibility. There's got to be interoperability standards. There's got to be an integrated information and communication system. There's got to be a data-exchange platform. We don't have any of that today. … We've got a long way to go."

Kristin Munsch of the Citizens Utility Board (left), and Sarah Nash of Marathon Capital | © *RTO Insider*

DER Issues

"The obvious environmental benefits of distributed energy resources can be thought of as being blunted … by the inability to control renewable generation and by its volatility," Caramanis said. "The way we reward and incentivize distributed energy resources — and, in particular, renewable generation — is introducing certain non-economical choices."

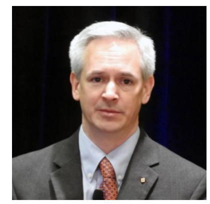
Information privacy and what he termed as "computational complexity" are also concerns. "How do we handle billions of bits of information that characterize the preferences of millions of" customers? he asked.

That complexity extends to the network as well. "The distribution wires are in abnormal configuration all the time because there are so many circuits that keep changing," Kristov said. Yet, communication and dispatching is between the grid operator and the resource owner, leaving the distribution-network owner uninformed about the situation.

With voltage changes of 5% able to damage appliances and cause brownouts, distribution networks require careful control, Caramanis said.

Utilities aren't accustomed to the rapid changes DER may require, speakers said.

"Utility [information technology] systems are very cumbersome, closed and expensive to adapt," said Kristin Munsch of the Citizens Utility Board.



"We don't want to sit there and deploy something that we're going to go back and regret and change a little bit later," said **Ben Kroposki** of the National Renewable Energy Laboratory.

Agents of Change

And there is no guarantee that consumers will respond to market signals in the way economists would expect. "The one thing we know is people make uneconomic decisions all the time," Munsch said. "We talk about these sort of transaction incentives and things we're going to create with this underlying assumption that, 'Well, all we have to do is explain it to them, and they're going to be fine with it,'" she said. "Well, they're not because on some level, utilities — whether it's energy, natural gas, water — they are different. There's an expectation they will be there when I want them, how I want them, at a price I can pay."

Large-scale strategic companies are seeing ways to help with economies of scale, Marathon Capital's Sarah Nash said. "A lot of these larger players who aren't necessarily within the traditional energy space, they're seeing ways to be able to supplement their offerings and move into the energy storage space," she said.

On a more traditional level, local governments "are on the front lines of these things," Owens said, and companies should "help them be ambassadors" of the system upgrades.

"Some get it; some fight it," he said. The

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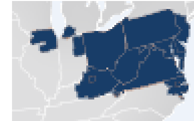
PJM NEWS



No Consensus Among PJM Stakeholders on Seasonal Resources

By Rory D. Sweeney

Less than half of PJM stakeholders considering the addition of a seasonal capacity product favor a change in the current rules.

Only 48% of members who voted in the Seasonal Capacity Resources Senior Task Force poll last week favored any change, while 52% chose the status quo.

None of the five alternatives to the status quo garnered much support, with the most popular proposal — retaining the base capacity product for an additional year, delivery year 2020/21 — topping out at 43%.

Thirty-four stakeholders representing 190 companies took part in the voting.

The results of the task force's vote were discussed at its meeting Friday. The sponsors of each option will incorporate the feedback they received into their proposals and resubmit them for reconsideration. Redlines are due Oct. 2, and the changes will be presented at the task force's next meeting on Oct. 14. Another vote may occur shortly thereafter based on stakeholders' response.

At question is how to allow seasonal and intermittent generation resources to offer as capacity under the tougher, year-round requirements of PJM's Capacity Performance rules.

Although CP rules allow multiple seasonal resources to combine in aggregated offers, no such offers have been entered in auctions thus far.

PJM sought to address the issue by relaxing the current prohibition on seasonal resources aggregating across locational deliverability areas, sub-regions such as electric distribution company zones used to evaluate locational constraints.

The RTO's proposed solution would allow resources to aggregate their production beyond LDA borders with unmatched resources moving up to the next LDA level until a match is found.

For example, an offer containing individual resources located in the EMAAC LDA and SWMAAC LDA would be modeled in the MAAC LDA. An offer with resources in COMED and EMAAC would be modeled in the "Rest of RTO." Performance penalties would be distributed evenly between the resources, no matter which failed to perform. This proposal received the support of only 32% of respondents.

Eligible resources would include intermittent resources, storage and summer-only demand response and energy efficiency. It would define the summer period as June through October and the following May; the winter period would run November through April.

Another proposal called winter performance equivalents would auction "WIPES" credits that allow capacity resources to not perform in the winter. Created by consultant James Wilson on behalf of the Consumer Advocates of the PJM States, the proposal was opposed by PJM and received only 21% support.

The proposal's release of 16,500 MW from their winter capacity obligations reduces operational reliability, PJM said in comments on the proposal. The RTO said a planning analysis cited by supporters "cannot capture all the complexities of real-time operations" because of its assumptions that generator forced outages are random and independent of each other. "The winter forced outage rates have exhibited a strong correlation with lower temperatures and higher loads. PJM has also observed common mode failures across generating units. For example, the disruption of a gas pipeline will force out all single-fuel gas units being served by that pipeline," PJM

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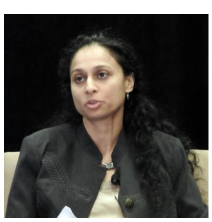
PJM Symposium: As DER Rises, Focus on Distribution System Needs

Continued from page 21

models are "smart cities" that have taken an active role in the process, he said.



"You'd be hard-pressed to find someone who says there isn't overlap" between the state oversight of retail energy sales and the federal oversight of wholesale markets, FERC's **Jignasa Gadani** said. "Is the new world going to be cooperative federalism? I don't know how otherwise you move forward."

Looking to the Future

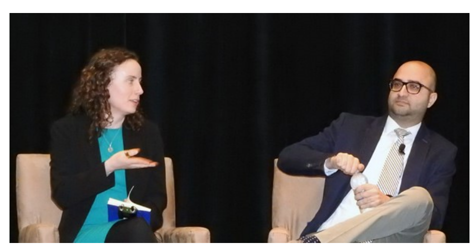
The largest changes, however, might be in perception.

Kristov said the wholesale markets that developed in the late 1990s have created a "commodity concept" of electricity.

"I think we need to question whether that's an adequate concept going forward because customers don't care [about] kilowatt-hours; they care about services," Kristov said. "The value of the grid used to be: get this commodity over here and move it over here, and that's not the business of the distribution company anymore. It's creating a new kind of network where the value may not be moving a commodity. It may be providing network services."

Caramanis disputed that, saying the grid "essentially commoditizes the quality of service."

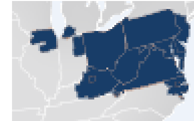
"At the end of the day, in order for this to happen, the utility has to have the right incentives as well," SolarCity's Seyed Madaeni said. "We've got to have a paradigm shift and make sure all the incentives are aligned."



Con Ed's Shelly Lyser and SolarCity's Seyed Madaeni | © RTO Insider

Consolidated Edison's Shelly Lyser added that properly valuing DERs' environmental benefits also is important.

PJM NEWS



MRC/MC Preview

Below is a summary of the issues scheduled to be brought to a vote at the 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 in Wilmington, Del., covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

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

Members will be asked to endorse the following manual changes:

A. Manual 14B & 14C: PJM Region Transmission Planning Process and Generation & Transmission Interconnection Facility Construction. Changes are related to the new equipment energization process.

B. Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA). Adds a new appendix defining a process checklist for energizing new equipment.

C. Manual 14B: PJM Region Transmission Planning Process. Makes revisions related to winter temperature ratings.

D. Manual 15: Cost Development Guidelines. Developed as part of the periodic review process.

3. Transmission Replacement Process Senior Task Force (TRPSTF) (9:30-9:50)

The task force's role will be discussed along with seeking approval to suspend several task-force activities in light of a recent FERC order. (See *FERC Orders PJM TOs to Change Rules on Supplemental Projects*.)

4. Governing Documents Enhancement & Clarification Subcommittee (GDECS) (9:50-10:00)

Proposed clarifications to "Member/Vendor Open and Competitive Bidding" will allow flexibility for noncompetitive items, such as office supplies. Revisions to governing document update formatting in the definition sections.

5. Release of Capacity in Delivery Year 2017/18 3rd Incremental Auction (10:00-10:20)

Members will be asked to approve PJM's proposal to use a straight-line offer curve for selling back excess capacity in February's third intermediate auction for the 2017/18 delivery year, as recommended by the Market Implementation Committee on Sept. 14. (See "PJM's Straight-Line Offer Curve Recommended for Capacity Sellback," *PJM Market Implementation Committee Briefs*.)

6. Metering Task Force (MTF) (10:20-10:30)

Members will be asked to approve revisions to Manual 1 to close gaps in understanding between staff and members on metering rules. (See "Metering Standards Ready for Stakeholder Vote," *PJM Markets and Reliability Committee Briefs*.)

7. Planning Committee Charter (10:30-10:35)

Members will be asked to approve proposed administrative updates to the Planning Committee Charter.

8. PJM Capacity Problem Statement / Issue Charge (10:35-11:35)

Ed Tatum, on behalf of a coalition of cooperatives and municipal utilities, will present a problem statement and issue charge calling for a holistic review of PJM's Reliability Pricing Model. (See *Proposal to Revisit PJM Capacity Model Receives Tepid Response*.)

Members Committee

1. Stated Rate (2:10-2:40)

Members will be asked to endorse proposed Tariff revisions to the administrative fee developed in conjunction with the Finance Committee. (See "PJM Eyes Fee Hike," *PJM Markets and Reliability and Members Committees Briefs*.)

2. Governing Documents Enhancement & Clarification Subcommittee (GDECS) (2:40-2:55)

Members will be asked to approve Operating Agreement revisions to clarify the "Member/Vendor Open and Competitive Bidding" section to allow flexibility for noncompetitive items, such as office supplies.

3. Cost Development Guidelines Periodic Review (2:55-3:15)

Members will be asked to endorse revisions to Manual 15 that were developed as part of the periodic review process.

4. First Energy Transmission Reorganization (3:15-3:45)

FirstEnergy will seek approval of proposed Operating Agreement revisions regarding the planned reorganization of its transmission assets. (See *NJ Opposition Derails FirstEnergy's Tx Reorganization — but not Projects*.)

No Consensus Among PJM Stakeholders on Seasonal Resources

Continued from page 22

said.

The RTO also said energy market costs would increase as capacity is released.

DR provider WeatherBug Home offered a solution that would create a way to measure and value seasonal DR by using the firm service level, a predetermined load reduction.

Load is currently paying for capacity that it doesn't use, and aggregation won't fix that, according to the proposal. Additionally, because there is far less winter demand, it will create a situation where winter assets will essentially collect "rent" by teaming with summer resources that are much more likely to be called to perform.

WeatherBug's plan calls for maintaining the current CP rules and limiting the amount of DR that can clear the auction. All resources can participate using their capacity ratings above their must-offer commitment, but such aggregations would only be eligible for performance bonuses if the load drops below unforced capacity obligations. This proposal received the least support at 17%.

EnerNOC's proposal was the same as PJM's, but with a different calculation for the balancing ratio that removes what the company called an "unreasonable barrier" for DR performance calculations. The plan received 33% approval.

SPP NEWS

FERC: SPP Treating P2P Customers Unfairly on Congestion Rights

By Rich Heidorn Jr.

FERC last week rejected proposed SPP Tariff revisions, saying they would unfairly favor network transmission customers over point-to-point customers in how the RTO awards congestion rights (ER16-1286-001, EL16-110).

The commission's ruling came in response to complaints by Southern Co., the American Wind Energy Association and the Wind Coalition.

The commission accepted changes that eliminated language SPP said had become obsolete as a result of the Integrated Marketplace. It also approved changes preventing firm point-to-point transmission customers whose service is subject to redispatch from obtaining long-term congestion rights (LTCRs).

But it rejected SPP's proposal to grant such rights to network customers subject to redispatch, setting the issue for a Section 206 hearing.

LTCRs, financial instruments that allow transmission customers to hedge congestion risk, can be obtained through purchase or conversion of auction revenue rights. Transmission customers can nominate ARRs between source and sink points over paths for which they have purchased transmission service.

When SPP receives a firm transmission service request requiring transmission upgrades, the RTO will start service before the upgrades are in service if it is able to temporarily address any constraints through redispatch.

SPP contended it was within its rights in treating point-to-point customers differently than network customers, arguing that the two classes are not "similarly situated." FERC said SPP's rationale was "not persuasive."

"While SPP notes that point-to-point transmission service uses a specific transmission path and network service uses the network as a whole, we note that SPP appears to ignore the fact that ARRs and LTCRs are allocated for both point-to-point and network service from a particular source point on the system serving a particular sink point on the system," the commission said.

Under SPP's proposal, the commission said, "firm point-to-point transmission service customers not subject to redispatch could receive a reduced portion of the available ARRs because such firm point-to-point transmission service would be competing with network service subject to redispatch."

The commission said SPP may be able to resolve its concerns by revising section 34.6 of its Tariff to limit the eligibility for ARRs and LTCRs of network customers with service subject to redispatch.

"Our preliminary review indicates that SPP should not provide network service customers subject to redispatch with any LTCRs until the transmission upgrades are placed into service and the service is no longer subject to redispatch," FERC said. "The commission notes that this approach would be consistent with SPP's rationale for not providing point-to-point customers subject to redispatch with LTCRs."

FERC NEWS

FERC Approves GMD Reliability Standard

Reliability Monitoring, Frequency Control Standards also Advance

By Michael Brooks and Rich Heidorn Jr.

WASHINGTON — FERC on Thursday approved a NERC reliability standard requiring grid operators to assess and protect against the threat of geomagnetic disturbances (RM15-11).

The final rule, effective 60 days after its publication in the *Federal Register*, is nearly identical to the commission's proposed rulemaking issued in May last year. Under the rule, certain transmission owners and planners will be required to assess the vulnerability of their systems to a "benchmark" GMD event, defined as a one-in-100-year occurrence. They would then need to submit plans to mitigate the identified vulnerabilities. (See *FERC Takes Next Step on GMD Standard* and *Questions and Answers on NERC's Proposed GMD Rules*.)

NERC will also need to submit a work plan within six months of the rule's effective date detailing how it will study GMD events in general, "given the limited historical geomagnetic data and because scientific understanding of such disturbances is still evolving," FERC said.

"While we recognize that scientific and operational research regarding GMD is ongoing, we believe that the potential threat to the Bulk Electric System warrants commission action at this time, including efforts to conduct critical GMD research," the commission said.

GMDs, caused by solar events that disrupt the planet's magnetic sphere, are considered "high-impact, low-frequency" events.

Response to Comments

FERC's original Notice of Proposed Rulemaking questioned certain aspects of NERC's proposed standard, TPL-007-1, including its reliance solely on spatial averaging to calculate the size of the impacted area in the benchmark event.

In comments submitted in response to the NOPR, NERC and other industry stakeholders defended the standard's methodology for the benchmark definition, but FERC said they did not provide any new information.

"NERC and industry comments largely focused on the NOPR's discussion of one possible example to address the directive" to modify the calculation so that it did not rely solely on spatially averaged data, FERC said. "However, while the method discussed in the NOPR is one possible option, the NOPR did not propose to direct NERC to develop revisions based on that option or any specific option."

The commission gave NERC 18 months to make those revisions, as well as to modify the standard to require that data from geomagnetically induced current monitors and magnetometers be made public and to establish specific deadlines for mitigation plans.

In a few cases, FERC declined to direct NERC to make revisions it had considered in the NOPR, instead including them as part of NERC's study homework.

For example, the commission had questioned whether the benchmark definition should also be modified to reflect that GMDs could have pronounced effects on lower geomagnetic latitudes. While it said that commenters who defended the original calculations did not provide any new information, the commission declined to direct NERC to revise the latitude scaling factor, saying it found "sufficient evidence to conclude that lower geomagnetic latitudes are, to some degree, less susceptible to the effects of GMD events."

The final rule represents the second stage of the commission's effort to protect against GMD, an effort that began in May 2013 with Order 779. The first stage, approved in June 2014, dealt with developing operating procedures for responding to GMDs and mitigating their effects.

Data Lacking

Commissioner Cheryl LaFleur called last week's order "a milestone reflecting over five years of work by the commission, our staff, NERC, industry and stakeholders to address the threats posed" to the grid by GMDs. "It's not the beginning of the end but the end of the beginning. We still have a lot of work to do."

LaFleur said the rule "appropriately balances the need for action on this important issue with a recognition that our under-

standing of the science around GMD events and their operational impacts on the grid is still evolving."

"One of the things we found frustrating in our tech conferences in developing the final rule was that so much of the magnetometer and monitoring data was from Canada or Europe when in fact we have one of the most highly developed electric grids in the world and very little public data on which to base our analysis."

Situational Awareness Requirements

The commission also gave final approval to reliability standards IRO-018-1 and TOP-010-1, which specify requirements for the real-time reliability monitoring and analysis capabilities of reliability coordinators, balancing authorities and transmission operators (RD16-6).

The standards implement Order 693, which specified operators' minimum capabilities, as well as the recommendations contained in a 2008 NERC best practices report and the joint FERC-NERC report on the 2011 Arizona-Southern California outage.

FERC noted that inadequate situational awareness was identified as one of the key causes of the 2003 Northeast blackout.

The joint report on the Arizona-Southern California outage recommended that entities "should take measures to ensure their real-time tools are adequate, operational and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems."

NERC said the new standards build on existing requirements by requiring applicable entities to provide them with indications of the quality of information being provided by their monitoring and analysis capabilities and notify them of real-time monitoring alarm failures.

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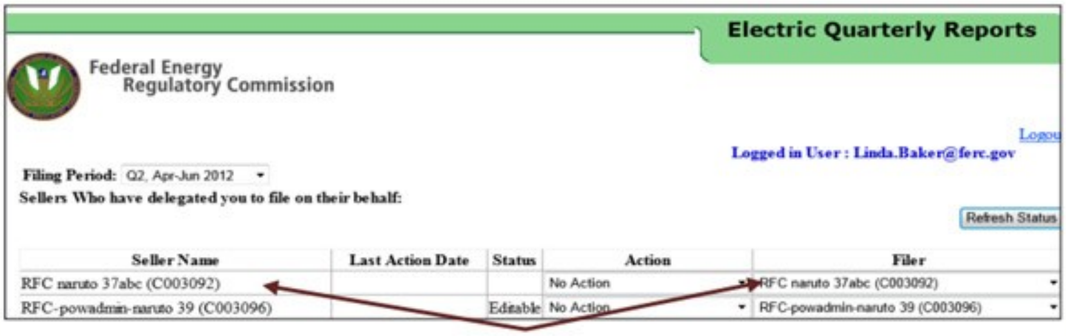
FERC NEWS

FERC Considering Changes to EQR Requirements

By Julie Gromer



Seller Name & Address

FERC is considering changes to its Electric Quarterly Report (EQR) rules, including requiring data on ancillary services transactions and changes to how financially settled trades are reported.

In its Sept. 22 notice of the proposed changes, the commission said it will accept comments on the proposals for 60 days following their publication in the *Federal Register* (RM01-8, RM10-12, RM12-3 and ER02-2001).

Ancillary Services

Transmission providers currently report ancillary services such as reactive supply and regulation in the EQR's Contract Data section. FERC is proposing that transmission providers also report information about transactions made under their ancillary services agreements in the EQR's Transaction Data section.

FERC said the information will "help the commission, the public and the industry determine the actual rates being charged for service under these agreements [and] increase price transparency into the wholesale ancillary services markets."

Booked Out Transactions

The commission also is seeking to clarify the reporting of "booked out" trades — those settled financially without any transmission of power.

FERC said EQR submissions relating to book outs frequently contain inconsistent or inaccurate information, making it difficult to determine how much power is being traded compared to how much is actually being delivered.

"We find that, based on the current EQR database configuration, it is not possible to differentiate book outs of energy or capacity because EQR filers do not have the option to distinguish between the two products," FERC wrote.

To create a distinction, FERC proposed amending its data dictionary to replace "booked out power" with the product names "booked out energy" and "booked out capacity."

FERC also seeks to clarify that booked out transactions must be reported in the EQR regardless of the number of parties involved. The notice provides examples of how booked out transactions should be reported when:

- two companies sell physical energy to each other for the same delivery period;
- one company sells energy to another company and, in real time, the company buying the energy signals the seller to reduce the amount of energy it is providing; and
- at least three companies are in a chain of energy sales and one company appears twice in that chain.

Tariffs and Time Zones

FERC also proposed that filers submit into the EQR's tariff reference fields tariff-related information that they currently submit in the e-Tariff system and that they include time zone information for transmission capacity reassignment transactions.

FERC Approves GMD Reliability Standard

Continued from page 25

Frequency Control Standards

The commission also gave preliminary approval to NERC's proposed standard BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements), which it said would clarify and consolidate existing frequency control requirements (RM16-13).

The commission said the proposed standards "support more accurate and comprehensive calculation of reporting area control error (ACE) by requiring timely reporting of an inability to calculate reporting ACE and by requiring balancing authorities to maintain minimum levels of annual availability of 99.5% for each balancing authority's system for calculating reporting ACE."

The NOPR also seeks the retirement of standards FAC-001-2 (Facility Interconnection Requirements) and BAL-006-2 (Inadvertent Interchange).

The commission said it was uncertain whether to support NERC's proposal to also retire requirement 15 of standard BAL-005-0.2b (Automatic Generation Control), which requires the maintenance and periodic testing of backup power supplies at primary control centers and other critical locations. "Depending on the explanation received in comments, the commission may issue a directive in the final rule to restore the substance of requirement R15 in the reliability standards," it said.

FERC NEWS

Clark Bids Farewell to FERC at Open Meeting

By Michael Brooks

WASHINGTON — After four years, Commissioner Tony Clark's last day at FERC will be Sept. 30, he said at his last, and 47th, open meeting Thursday.

Clark said that given the date would be the end of a week, pay period, quarter and the federal fiscal year, "this may be God's way of telling me that that's probably the right day to move on."

The remaining days of his tenure will be mostly spent emptying his office, he said, though he would be available in case a quorum (a minimum of three commissioners) is needed for decisions in which another commissioner could not participate. Chairman Norman Bay recuses himself from issues he dealt with as head of the commission's Office of Enforcement, and Commissioner Colette Honorable recuses herself from matters that were before her as a regulator in Arkansas.

Bay said he did not foresee any quorum problems following Clark's official departure. "I feel like we're on top of that. We've known for some time that Commissioner Clark would be leaving, and so we've been planning for the completion of any orders where his vote would be required." Clark indicated in January that he would not seek another term.

A former North Dakota regulator, Clark is the lone Republican on the commission after the departure of Philip Moeller last year.

Clark's three Democratic colleagues praised him for his meticulous thinking and ability to work through disagreements civilly.

"You've been an outstanding public servant," Bay said. "I know that every place you've gone to, you have made [it] better with your thoughtfulness, your encyclopedic knowledge of policy, your reasonableness and your collegiality."

Commissioner Cheryl LaFleur joked about her disappointment at not being able to influence Clark more after he joined the commission. "From the very first day you walked in, you were always on top of the issues, crystal clear in your thinking, pragmatic and very, very decisive," she said.

"I have enjoyed working with him very much, even though we come from different places," Honorable said. "But in many ways, we have been quite a lot alike, I would say, in terms of … our commitment to serving."

Honorable joked that they agreed on many things, but not on their favorite president. Her parting gift to him was a mug featuring the Democratic nominees for president and vice president, Hillary Clinton and Tim Kaine. Clark promptly hid the mug behind his name plate.

"Hopefully at FERC, people see an agency in a town that is sometimes dysfunctional, but an agency that I think is very functional," Clark said. "Although we don't agree on every item — that's to be expected — … where we do disagree, we can do so without being disagreeable."

Clark was nominated by President Obama after Sen. Mitch McConnell (R-Ky.) forwarded his name to the White House. He said he has not heard anything about Obama nominating replacements for the two GOP vacancies. He speculated that new commissioners may be among a group of nominees submitted by the next president.

The best chance for a nominee to get confirmed by the Senate would be during the lame-duck session after the November elections as part of a package of nominees, said Dan Blair, CEO of the National Academy of Public Administration, a Congressionally chartered think tank that provides advice to public officials.

But there are many different permutations of what could happen based on the results of both the presidential and senatorial elections. For example, Blair said, if Republican presidential nominee Donald Trump wins the White House, McConnell, the majority leader, could defer to him on who should go to FERC.

Many federal agencies suffer member shortages while the White House and Senate negotiate over nominations. Obama may be holding out on nominating anyone to FERC until he can reach an agreement on a Democratic nominee for a different agency, Blair said. "There's a lot of horse trading that goes on behind the scenes. You have to look outside the commission."

Tony Clark received parting gifts from each of his fellow commissioners, including a lookalike bobblehead from Chairman Norman Bay.
| *Norman Bay*

When asked if he had heard anything about reinforcements, Bay said only, "The nomination process I leave to the White House and to the Senate."

Nicole Daigle, communications director for the Senate Energy and Natural Resources Committee, said Chairman Lisa Murkowski (R-Alaska) "is concerned that FERC will be down to three commissioners."

"It is important that we have a full complement of members on the commission," Daigle said in a statement.

Daigle did not respond when asked whether Murkowski had suggested anyone to McConnell or whether McConnell had forwarded any names to Obama.

A spokesman for McConnell said the senator would not comment until the president submitted a nomination. The White House did not respond to a request for comment.

Clark said he was going to take some time to relax before spending the remainder of October thinking about his next job.

FERC Chairman Norman Bay (left) with Commissioner Tony Clark before the start of last week's open meeting.
| *© RTO Insider*

FERC News

FERC Considers Changes to Market Power Analyses

Continued from page 2

Market Share Analyses

The commission said its current merger analysis is a forward-looking review focused on how a transaction changes market concentration "and not an examination of market share changes or accumulation of market share over time."

Thus, the commission said it is considering adding a market share analysis measuring the size of the applicant relative to other suppliers, allowing it to "determine if a seller has obtained a significant share in a specific market either through a series of transactions or a combination of transactions and construction, allowing for the accumulation of market power without one particular transaction triggering concerns."

The MBRA wholesale market share screen determines whether a seller has a dominant market position by analyzing the number of megawatts of uncommitted capacity it controls relative to the uncommitted capacity of the entire market. Sellers with less than a 20% market share during all seasons pass the test.

Supply Curve Analysis

The commission said it also is weighing whether to incorporate into its merger review a supply curve analysis to determine whether the acquisition would give the purchasing company the ability and incentive to exercise market power by withholding output from some generators to benefit other units and increase its overall profits.

The analysis would be more granular than the delivered price test, which measures aggregate capacity but not the breakdown by baseload, intermediate and peaking units.

"A supply curve analysis would enable the commission to identify situations that typical [Herfindahl-Hirschman Index] analyses do not capture, including situations where mergers that result in changes in market concentration below the thresholds that merit further scrutiny from an HHI perspective may still have the ability and incentive to raise prices above competitive levels," the commission said.

Capacity Associated with Power Purchase Agreements

FERC also sees a need to change how it accounts for capacity subject to long-term firm power purchase agreements.

If a utility signs a long-term firm PPA for the output of a generating facility before filing an application to purchase that generator, the commission has usually attributed the generator's capacity to the purchasing utility. That means the company's acquisition of the plant would not be seen as increasing its market share.

"While the current approach of attributing the capacity of the facility to the purchaser is appropriate in the context of the market-based rate market power analysis, in the Section 203 context the change in market concentration may extend beyond the terms of the PPA," FERC said. "For example, if a transaction conveys ownership over a generation facility where a PPA is expiring in two years, the transaction may prevent competitive supply from re-entering the market."

HHI (Market Concentration) Thresholds		
Market	**1992 Guidelines**	**2010 Guidelines**
Unconcentrated	<1000	<1500
Moderately Concentrated	1000-1800	1500-2500
Highly Concentrated	>1800	>2500
HHI Changes Potentially Raising Significant Competitive Concerns		
Moderately Concentrated Markets	>100	>100
Concentrated Markets	>50	>100, <200
HHI Changes Presumed Likely to Enhance Market Power		
Concentrated Markets	>100	>200

Source: FERC

Applicant Merger-Related Documents

FERC noted that merger applicants are required to submit to the Department of Justice and Federal Trade Commission both internal reports and those of consultants that concern the competitive effects of an acquisition.

"We believe these merger-related documents could be useful in the commission's understanding of an applicant's competitive analysis screen by providing additional information regarding, for example, the relevant geographic market definition or anticipated unit retirements," it said.

Blanket Authorizations

FERC also is taking another look at its use of blanket authorizations — waivers of commission review for certain Section 203 transactions. The commission said it is considering canceling blanket authorizations for some types of deals and extending them to others.

"Since these blanket authorizations were granted, industry has undergone substantial change, including continued market development and expansion of RTOs/ISOs [and] consolidation among utilities, such that the conditions that gave rise to the blanket authorizations currently in effect may no longer be appropriate," FERC said. "For example, it may no longer be appropriate to grant blanket authorizations to holding companies that only hold exempt wholesale generators, as is granted in 18 CFR 33.1(c)(8), as exempt wholesale generators now make up a significant portion of supply and any transaction involving these generators could affect wholesale rates by impacting competition."

Exempt wholesale generators, a category created under the Energy Policy Act of 1992, are independent units that sell exclusively to wholesale customers and were exempt from some requirements of the Public Utility Holding Company Act of 1935. PUCHA was repealed in 2005.

Michael Brooks contributed to this report.

Great Plains Energy, Westar Shareholders OK $12.2B Deal

By Amanda Durish Cook

Shareholders voted overwhelmingly Monday to approve Great Plains Energy's $12.2 billion acquisition of Westar Energy.

Shareholders cast their votes in separate meetings at Great Plains' headquarters in Kansas City, Mo., and Topeka, Kan., where Westar is based. Company spokesmen said stakeholders approved all proposals necessary with at least 95% percent support.

Great Plains CEO Terry Bassham called the move "a great transaction" for stakeholders of both companies. Great Plains' $12.2 billion offer includes $3.6 billion of Westar's outstanding debt.

Westar CEO Mark Ruelle said the transaction would be completed next spring. Both CEOs said the acquisition will create a stronger company, with Ruelle adding that shareholder support "clearly demonstrates the value of combining Westar and Great Plains Energy."

"The combined generation portfolio of the new utility will be more diverse and sustainable," Bassham said. "Once this transaction is complete, more than 45% of our combined retail customer demand will be met with emission-free energy, and we will have one of the largest wind generation portfolios in the United States. This helps us maintain reliable, low-cost energy for all of the residential and business customers we serve."

Westar's 6,267 MW of generation is mostly coal-fired. Great Plains will walk away from the deal with 1.5 million customers in Kansas and Missouri, nearly 13,000 MW of generation and 10,000 miles of transmission lines.

Currently Great Plains and Westar jointly own the Wolf Creek Nuclear Generating Station and the La Cygne and Jeffrey power plants.

Westar's shareholders will receive $60/share, paid in $51 cash and $9 in Great Plains common stock. Immediately after the vote, Westar stock was trending upward at $56.73/share.

Great Plains, parent of Kansas City Power and Light, announced plans to buy Westar in May. (See *KCP&L's Parent Great Plains Energy to Buy Westar for $12.2 Billion*.)

Westar and Great Plains settled three lawsuits challenging the proposed merger, according to a U.S. Securities and Exchange Commission filing last week.

According to *The Topeka Capital-Journal*, a lawyer for one of the plaintiffs said the agreement will allow eight unsuccessful bidders to submit new bids. Attorney Derrick Farrell said the settlement required Westar and Great Plains to waive confidentiality provisions.

Andy Pusateri, a utilities analyst for Edward Jones, told the newspaper the settlement is unlikely to start a bidding war for Westar, saying Great Plains offered "a pretty significant premium."

Westar also thinks the scenario is unlikely. Among other complaints, the lawsuits also alleged that the deal unfairly favored Great Plains Energy's proposal while discouraging other and potentially better third-party bids.

"It is common to have someone file a lawsuit when mergers are announced. We were able to settle those lawsuits by simply modifying some of the language in the bidding documents. With that, the litigants agreed to stand down," Westar wrote of the settlements.

The purchase still requires approval from the Kansas Corporation Commission, FERC, the Federal Trade Commission and the Nuclear Regulatory Commission.

The Missouri Public Service Commission wants in on the approval process, but Great Plains has said that Missouri regulators have no jurisdiction over the sale.

Westar would be the second acquisition in eight years for Great Plains, which acquired Missouri utility Aquila in 2008.

COMPANY BRIEFS

Duke Energy Agrees to $6 Million Dan River Fine

The long saga of the Duke Energy coal ash spill that coated the Dan River with up to 39 million tons of toxic coal ash from a retired coal-fired plant in February 2014 came to an end Friday when the company agreed to pay a $6 million fine to the North Carolina Department of Environmental Quality. The company already settled federal pollution violations with a $102 million settlement in 2015.

The state first fined the company a $6.8 million civil penalty, which Duke called "entirely arbitrary and capricious." The company did not say why it was now agreeing to a fine that is only slightly lower than the original, as it agreed with the DEQ not to make any public statements that were not mutually cleared.

The two sides did say that it is "in the best interest of the parties, the environment and the citizens of North Carolina that they enter into a compromise to avoid the time and expense of prolonged litigation."

More: *Charlotte Business Journal*

AEP Texas Corporate Reorganization Approved

FERC granted American Electric Power's request that its AEP Texas North and AEP Texas Central affiliates be combined into a single organization. The companies will operate under the name AEP Texas, with AEP Utilities, an AEP subsidiary, as its direct parent.

The commission dismissed the Oklahoma Municipal Power Authority's request that it not address FERC's jurisdiction over AEP Texas' wholesale transmission service, finding "no evidence that either state or federal regulation will be impaired."

AEP told the commission it expects the organizational changes to take place by year-end.

More: *EC16-135*

FERC OKs Fortis Acquisition of ITC Holdings

FERC on Friday approved ITC Holdings' acquisition by Canadian utility operator Fortis and a Singapore-based investment fund. ITC, the largest independent transmission operator in the U.S., agreed to the $11.3 billion sale in February. (See *Fortis to Acquire ITC Holdings for $11.3B*.)

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COMPANY BRIEFS

Continued from page 29

Fortis, which owns New York's Central Hudson Gas and Electric and Tucson Gas & Electric, is purchasing most of ITC. GIC Ventures, an affiliate of an investment company that manages the government of Singapore's foreign reserves, is purchasing the remaining 19.9%. ITC will remain a standalone transmission company.

FERC said the transaction raised no competitive concerns because ITC does not control any generating assets, and neither Fortis nor GIC own generation or natural gas assets in MISO, home to much of ITC's transmission network. The deal, which the companies expect to close by the end of the year, had already been approved by state regulators in Wisconsin and Missouri.

More: EC16-110, ITC Holdings

NextEra Energy's Brady Wind Farms near Completion

Construction of NextEra Energy's 87-turbine Brady Wind I project is 65% complete and concrete is being poured for the foundations of Brady Wind II, a nearby 72-turbine wind farm, according to the company.

Both projects are slated for completion by the end of the year. An 18.2-mile transmission line that will transmit the power to Basin Electric Power Cooperative, which signed a power purchase agreement with NextEra, will be completed in a few weeks.

More: The Dickinson Press

PG&E Appoints Eric Mullins To Company Board

PG&E last week announced the election of Eric Mullins to its board of directors and to the board of its Pacific Gas and Electric subsidiary.

Mullins is the managing director and co-CEO of Lime Rock Resources, a private equity fund specializing in the acquisition and operation of oil and natural gas properties. Before cofounding Lime Rock, Mullins worked for 15 years in the investment banking division of Goldman Sachs, where he served as managing director in the company's energy and power group.

"As we position PG&E for continued long-term success, we welcome Eric's expert counsel around our strategy and audit functions," PG&E CEO Tony Earley said. "Eric's deep financial background and familiarity with the energy sector will be invaluable assets for us."

More: PG&E

Alliant Breaks Ground On Wisconsin Plant

Alliant Energy has started construction of a 700-MW natural gas-fired generating station near Beloit, Wisc., that will combine the power plant with an adjacent solar farm in the largest paired generation station of its type in the state.

The company's Riverside Energy Center is already home to one solar farm. The $700 million project includes a second solar installation designed to offset power used by the new gas-fired plant, company officials said. When the second solar farm is completed, there will be 8,000 panels generating solar power.

The gas-fired plant is scheduled to be in service by 2020.

More: GazetteXtra

Xcel Announces Expansion of Wind Energy in Midwest

Xcel Energy says it is planning to invest $2 billion to build eight to 10 wind farms in Minnesota, the Dakotas, Wisconsin and Michigan, with an eye toward generating about 1,500 MW of electricity.

The company said it will own and operate some of the proposed wind facilities and enter into power purchase agreements with the operators of others.

"We believe this is one of the largest wind acquisitions in the country," said Chris Clark, president of Xcel's Upper Midwest Operations. He said the wind farms should come online between 2017 and 2020. Xcel is looking to renewable energy — primarily wind — to offset its planned retreat from coal-fired generation.

More: Star Tribune

Dynegy Wins IPA's MISO Zone 4 Capacity Auction

Dynegy was chosen as one of the winners of the Illinois Power Agency's MISO Zone 4 capacity procurement auction for 2017/2018 and 2018/2019.

The company's share of the auction was not announced, but the weighted average price was $143.20 and $137.25/MW-day, respectively. The total capacity from winning bidders was for 1389 MW for the first period and 465 MW for 2018/2019.

More: Dynegy

FEDERAL BRIEFS

NRC Wants More Details On Seabrook Degradation

The Nuclear Regulatory Commission wants to know more about NextEra Energy's plans to respond to the degradation of concrete at its Seabrook nuclear generating station in New Hampshire. An alkali-silica chemical reaction is causing the plant's concrete walls to break down.

NextEra's amended license proposal did not contain sufficient details on how it would address the issue, according to a NRC spokesman. The company has until Oct. 3 to provide more details on how it is going to stop, or counter, the chemical reaction. NextEra is seeking a 20-year extension to the plant's operating license, which is currently set to expire in 2030.

The commission has not deemed the degradation a safety issue, but it wants to know how the company is going to tackle long-term preventative measures.

More: Seacoastonline.com

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FEDERAL BRIEFS

Continued from page 30

Exelon Facing $1.45B Tax Bill, Court Says

The Tax Court has ordered Exelon to pay as much as $1.45 billion in back federal taxes, penalties and interest.

The bill resulted from a tax strategy that Commonwealth Edison used after its $4.8 billion sale of coal-fired power plants in 1999. To shield itself from the potential tax bill, ComEd sunk much of the proceeds in long-term leases of power plants in other parts of the country and leased the plants back to the owner-operators.

Exelon must now decide whether it wants to pay or appeal. Even if it to decides to appeal, it still must pay the Internal Revenue Service or post a bond, the company said in a Securities and Exchange Commission filing. "Exelon is still evaluating the Tax Court's decision and considering next steps," the company said.

More: *Crain's Chicago Business*

Environmental Groups File Appeal of AIM Approval

A coalition of environmental groups asked the D.C. Circuit Court of Appeals last week to stay construction of Spectra Energy's Algonquin Incremental Market natural gas pipeline project while its appeal of FERC's approval is pending. The pipeline project is designed to transport natural gas from shale-gas fields in the Mid-Atlantic region to markets in the Northeast and Canada.

The groups noted that the court reprimanded FERC for approving a similar project in 2014, but that by the time it had reached its decision, construction was almost complete.

More: *Ossining Patch*

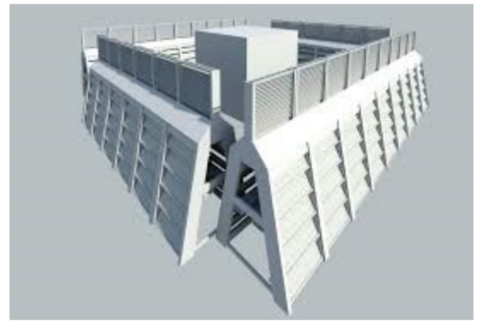
Offshore Wind Survey Work off Mass. to Start

An offshore wind developer has begun surveys off the Massachusetts coast, where it leases about 160,000 acres from the Bureau of Ocean Energy Management.

OffshoreMW is conducting the work south of Martha's Vineyard in preparation for the possible construction of offshore wind facilities in the area. Seafloor and sub-seafloor surveys will be taken by the crew of the *Shearwater* research vessel. The company was the successful bidder for the lease area in 2015.

More: *CapeCodToday.com*

Federal Lab Develops Substation Armor



The Idaho National Laboratory has developed a ballistic barrier system designed to protect substations against threats such as bullets, explosives and tornadoes.

The lab started working on the patent-pending Transformer Protection Barrier after a substation in California was targeted by a marksman who fired up to 150 rounds at it, causing an estimated $15 million damage to 17 transformers.

"We are trying to be proactive and provide solutions to threats when they emerge," said Chad Landon, head of INL's Defense Systems Materials Technology and Physical Analysis department. "Based on the 2013 incident and similar situations, we decided to come up with a solution."

More: *Idaho National Laboratory*

STATE BRIEFS

CALIFORNIA

State Audit Reveals Faults In CPUC Contract Practices

The Public Utilities Commission failed to follow state rules for awarding noncompetitive contracts, did not guard against the appearance of improper influence from utilities when making decisions and failed to fully disclose important communications, according to a new state audit.

The audit focused largely on the CPUC's contracting methods, which showed the agency spent $2.4 million on unexplained contracts and failed to monitor performance in a third of the contracts that were reviewed.

"The shortcomings we noted in CPUC contracting practices resulted from a lax control environment that the CPUC has allowed to persist," the auditors said.

More: *Los Angeles Times*

SDG&E Challenges CCA Lobbying Rules

San Diego Gas and Electric is challenging state rules governing the manner in which a company-backed shareholder group can lobby against the creation of community choice aggregators (CCAs).

In August, SDG&E became the first utility in the state to get approval from the Public Utilities Commission to create such a lobbying group. But the company says the commission's framework is too onerous and exceeds what is allowable under a state law.

CCAs allow elected city officials the authority to purchase power for ratepayers instead of utilities, which still operate the distribution system. They have become increasingly popular among cities seeking to service its load entirely through renewable energy.

More: *The San Diego Union-Tribune*

KANSAS

Former Co-op Employee Sentenced for Embezzlement

A former Sedgwick County Electric Cooperative employee was sentenced to five years' probation for embezzling thousands from the co-op.

Jamie L. Martin, 48, was ordered to repay

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STATE BRIEFS

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the co-op about $187,000 and another $97,000 to cover the costs of the audit that uncovered the theft. She could serve 22 months in prison if she fails to abide by the terms of her probation.

Martin pocketed cash payments from customers, altering computer records to conceal the losses.

More: *The Wichita Eagle*

MICHIGAN

Bill Would Prevent Customers From Paying for Leaked Gas

State Rep. Jeff Irwin (D-Ann Arbor) has introduced legislation that would block utilities from charging customers for gas that leaks from their systems before it can be sold.

Irwin

Irwin said he was inspired to draft House Bill 5913 after he read a recent economic analysis that concluded utilities are less motivated to fix gas leaks when they can recover the cost of leaked gas in rates. "The public should not be subsidizing gas leaks," Irwin said in a statement. "Charging customers for gas that they never get picks their pockets and pollutes the environment."

Consumers Energy spokesman Dan Bishop said his utility was reviewing the bill. Bishop also called the wasted gas issue a *de minimis* problem, meaning it didn't merit consideration.

More: *MLive*

NEW MEXICO

Albuquerque Approves Resolution for 25% Solar

The Albuquerque City Council unanimously approved a resolution that aims to power city-owned buildings and facilities 25% through solar energy by 2025.

The city's Energy Conservation Council will put together a plan for the mayor and council with implementation options and recommendations to reach the 25% goal.

More: *Albuquerque Business First*

OHIO

New Natural Gas-Fired Plant Approved by Siting Board

The Power Siting Board has approved plans from Advanced Power Services to build a $1.1 billion, 1,105-MW natural gas-fired power plant in Columbiana County. The location will give the plant direct access to the region's shale gas resources.

Construction is set to begin in January, and the plant should be operational by 2020. The plant will replace about a fifth of the capacity that American Electric Power sold off in a deal announced last week.

More: *Columbus Business First*

RHODE ISLAND

Town Council Opposes Invenergy Power Plant

The Burrillville Town Council voted unanimously to oppose the construction of a 1,000-MW natural gas power plant, ending its official silence on the controversial $700 million Invenergy project.

The council voted at a special meeting held in a high school auditorium to accommodate larger-than-usual attendance. Members said they took the stance only last week so as not to unduly influence the boards and commissions that had been asked to submit advisory opinions on the Clear River Energy Center, which would be located in woodlands near the town.

The town had told the state's Energy Facility Siting Board that Invenergy's application was incomplete. Additionally, local authorities that were counted on to provide cooling water for the plant have withdrawn agreements to do so. (See Proposed RI Power Plant Loses Cooling Water Source, Seeks Delay.)

More: *Providence Journal*

VIRGINIA

State Approves Dominion's Coal Ash Wastewater Plan

The State Water Control Board approved Dominion Virginia Power's plan to treat the millions of gallons of coal ash wastewater stored in ponds and discharge it into the James River.

Dominion said that after the wastewater has been treated and discharged, it will no longer use wastewater ponds to store coal ash and will switch to a dry storage method in which the ash will be transferred to lined landfills.

The approval came over the objections of environmental groups. "We are just disappointed that the board did not take steps to further improve the permit," said an attorney with the Southern Environmental Law Center.

More: *Richmond Times-Dispatch*

Competitive Power Ventures Lobbyist, Former Cuomo Aides Named in Bribery Indictment

Continued from page 1

Howe's plea arrangement, Howe arranged bribes to be paid by CPV and another company, COR Development.

Valley Energy Center rendering | *CPV*

The bribes allegedly came as CPV was arranging to build the 650-MW Valley Energy Center in Orange County, a combined cycle plant that was granted a certificate of public convenience and necessity a little more than two years ago. It is still under construction and is seen as necessary to relieve downstate transmission constraints.

The top target in the indictment is Joseph Percoco, who formerly held a $169,000-a-year post as Cuomo's executive deputy secretary. He left the state payroll in January, taking a position at Madison Square Garden.

Aiello

According to the indictments and a release issued by Preet Bharara, the U.S. Attorney for the Southern District of New York, Percoco is accused of taking more than $315,000 in bribes from Kelly and two executives with Syracuse developer COR Development, Steven Aiello and Joseph Gerardi.

Gerardi

Kelly did not return calls for comment by press time.

"CPV takes the charges handed down today very seriously," the company said in a statement. "We are extremely disappointed in the alleged conduct, which is in direct contradiction to CPV's core values and expectations of our staff. Braith Kelly is no longer employed at the company. We will continue to cooperate fully with this investigation until a final determination is made."

Kaloyeros

The indictment also names Alain Kaloyeros, president of the State University of New York Polytechnic Institute, as being involved in what federal authorities called "two overlapping criminal schemes involving bribery, corruption and fraud in the award of hundreds of millions of dollars in state contracts and other official state benefits."

Bharara

According to the statement from Bharara, Percoco was experiencing financial problems at the time that CPV was seeking New York's approval of the power plant. Kelly gave Percoco "expensive meals and a Hamptons fishing trip" in the beginning. But later, at Percoco's request, CPV hired Percoco's wife at about $90,000 a year for a job that didn't require much work.

In exchange, according to the charging document, Percoco used his official position to help CPV get lower-cost emissions credits from the state for a plant the company was building in New Jersey, and he helped arrange a power purchase agreement with New York. As a result, CPV was expected to save about $100 million in development costs.

The indictment says Kelly hid the monthly payments to Percoco and his wife through a CPV consultant. Percoco is also accused of lying when he told CPV that he had received an ethics opinion from Cuomo's office approving his wife's hiring. He also hid the payments he received from CPV, failing to list them on financial disclosure forms.

News of the investigation broke earlier this year. (See *CPV Power Plant Ensnared in Federal Corruption Probe*.) At the time, CPV was named as a company that made payments to Percoco, but it wasn't identified as a target of criminal charges.

Thursday's indictment identifies Kelly as a co-conspirator, saying he "willfully and knowingly did corruptly give" Percoco bribes "in order for Percoco to influence regulatory approvals and funding related to the development of a power plant in Orange County, N.Y., and take other official action to benefit" CPV.

The rest of the indictment has to do with other attempts to subvert the state regulatory process, according to the release. The primary focus of the investigation is the so-called Buffalo Billion economic development program championed by Cuomo. Bharara's probe began last fall.

A centerpiece of that program is $750 million in direct state aid and tax credits to SolarCity, which is building a 1-GW solar panel factory, the largest of its kind in the Western Hemisphere, according to the state.