RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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Peak Touts 'Independent' Western Market Plan

By Jason Fordney

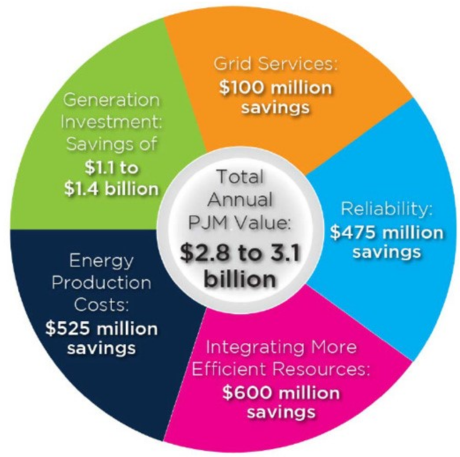
Peak Reliability and PJM officials last week promoted the independent and self-governing nature of their proposed Western energy market in an attempt to differentiate the effort from a competing initiative by CAISO.

"Our blank state for market governance really resonates with people, because they see they don't have to inherit a governance structure from one entity or be burdened by a structure that is tied to a particular state," Pete Hoelscher, Peak's chief strategy officer, said during a Feb. 27 conference call.

Peak officials provided more details on the proposed market, along with feedback they have received from industry participants.

One major concern among participants interested in the market: getting the full and appropriate value for generation and transmission assets "because that is not happening in all cases today," Hoelscher added.

In a parallel development, CAISO earlier this year announced a plan to bring day-ahead functions into its Western Energy Imbalance Market (EIM). (See *CAISO Plan Extends Day-Ahead Market to EIM*.) The California State Assembly this week also kicked off yet another legislative effort to regionalize CAISO, possibly setting up competition for who would create and operate a full Western RTO. (See *Calif. Lawmakers Relaunch CAISO Regionalization*.)



| PJM Connext, Peak Reliability

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PJM Chief Confident on Western Market Proposal (p.4)

Van Welie: ISO-NE in 'Race' to Replace Retirements

By Michael Kuser

ISO-NE is "in a race" to relieve natural gas pipelines constraints and interconnect new generation before New England loses older, uneconomic resources, CEO Gordon van Welie said last week.

"If there's a mismatch between the speed of those two or three activities, we're going to have to do something to slow things down so that we keep the grid reliable," van Welie told reporters in an online briefing on the state of the region's power grid.

"The more we constrain oil, the more complicated, the more tenuous it makes our operations," he said. "We have resources that are retiring, we have state environmental regulations that are aggressively lowering the amount of emissions that can be produced by fossil generators, and we have the states moving forward aggressively to invest in behind-the-meter resources, including energy efficiency and new renewable resources."

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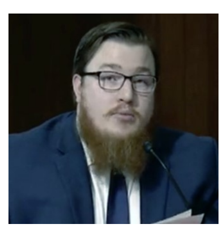
Let Industry Lead on Grid Defenses, ex-NSA Cyber Expert Says

Role for National Guard Viewed in Recovery

By Rich Heidorn Jr.

FERC should stop issuing new cybersecurity standards to allow the electric industry to develop innovative defenses to vulnerable industrial control systems — and the National Guard should be ready to respond if an attack succeeds, witnesses told the Senate Energy and Natural Resources Committee on Thursday.

The panel heard from Assistant Energy Secretary Bruce Walker, a former National Security Agency cyber sleuth, the CEO of the National Rural Electric Cooperative Association (NRECA) and two academics in a nearly two-hour hearing. Chairman Lisa Murkowski (R-Alaska) opened the hearing by asking for advice on what Congress should do after



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IN THIS WEEK'S ISSUE

CAISO NEWS

Powelson: States Pushing RTOs' Backs to the Wall

By Jason Fordney

SAN DIEGO — Some states are creating energy policies without enough regard for grid reliability, possibly forcing federal regulators to intervene in the future, FERC Commissioner Robert Powelson said last week.

"We are seeing states that are pushing the envelope in some of these market constructs, with no understanding of what this means to overall electric reliability," Powelson told the Western Power Trading Forum (WPTF) on March 2. "It is pushing the RTOs and the ISOs to a very 'back-to-the-wall' scenario, and that's not good.

"FERC is going to have to rightly interject itself into some of these states," he said.

Powelson addressed the WPTF in an informal speech interjected with humor and endorsements of his beloved Philadelphia Eagles, the reigning Super Bowl champions.

He noted that California and states in New England are pushing more renewables onto the system, creating issues such as CAISO's "duck curve" and forcing oil units to run during this winter's "bomb cyclone" in ISO-NE. He also said that four years ago he would have laughed if someone told him that gas-fired units in some California zones would be coming to FERC for approval for reliability-must-run contracts. (See FERC Orders Hearing, Settlement Talks for Calpine RMRs.)

Other California issues that concern Powelson: the possible phase-out of the Aliso Canyon gas storage field, as well as the retirement of the San Onofre and Diablo Canyon nuclear power plants.

While Powelson said he respects states' rights, he added that "in some of those cases, the states get to choose the winners and losers in those markets, but the FERC has to deal with the moral hazards created by those decisions."

Organized markets are benefiting consumers, who are increasingly becoming "prosumers" through using technology such as smartphones to manage energy usage, Powelson said. States like Nevada are considering retail competition, penetration of renewables is growing and FERC is contributing through actions such as its recent order on energy storage, he noted. (See FERC Rules to Boost Storage Role in Markets.)

But states cannot consider the policy aspect without heavily considering system balancing and reliability, he said. He also suggested the industry more strongly promote organized market competition to state governors and leaders, and he discussed a "cooperative federalism model" for FERC.

"There is a tectonic shift taking place across the ISO and RTOS, and a lot of that is driven by states," Powelson said, pointing to the growth of markets across the West. "The fever of electric competition and competitive markets is going viral these days, and I think that's a good thing."

But he acknowledged there are differences in regional markets, "and you have to respect that, and I am learning that rather quickly." He said, "I was warned not to talk about capacity markets" at the WPTF meeting, drawing laughter.

Powelson also mentioned the Department of Energy's proposed grid resilience pricing rule that would have bolstered nuclear and coal units to maintain reliability, which he called "DOA." (See Powelson, Regulators Talk Resiliency, Slam DOE NOPR.) He said that FERC's rejection of the proposal shows that the rule of law and independence still matter at the commission.

Peak Touts 'Independent' Western Market Plan

Continued from page 1

While Peak officials have previously said they aren't setting out to create an RTO, the organization said last week that its proposal is a pathway to developing one. Peak expects to publish a business plan on March 30 and hopes that by mid-April interested parties will enter into nonbinding agreements to assist in market governance and design. Binding agreements are targeted for June, and the goal is to have the market go live in June 2020.

Peak said that potential participants in the new market have expressed doubt that it can be operational by the scheduled target date of mid-2020 because of technical, operational and regulatory tasks, but Peak officials are stressing the operational experience of PJM, which operates a 13-state eastern energy market.

Other commenters to Peak noted that they have already invested in joining the EIM and are receiving financial benefits from the real-time balancing market. Some have told Peak that CAISO's proposed day-ahead market across the EIM seems like the only foreseeable next step in developing a Western market. Others say the West needs more fuel diversity and participation, according to a Peak presentation.

Based on feedback, Peak's services would not include a capacity market, consolidation of open access transmission tariffs, or regional/sub-regional system planning for reliability, operational performance, public policy, market efficiency or interconnection.

	Peak (w/o AESO)	PJM
Millions of people served	~74	65
Load in megawatts*	147,565	165,492
MW of generating capacity	~267,000	178,563
Miles of transmission lines	110,192	84,042
2017 GWh of annual energy	~820,000	773,522
Generation sources	3,482	1,379
Square miles of territory	~1,600,000	243,417
States served	14 + BC, Baja	13 + DC

| *PJM Connext, Peak Reliability*

Peak and PJM Connext announced their joint effort to develop a market in January. Visualized for day one is reliability coordination services, real-time and day-ahead energy markets, financial transmission rights allocation, balancing authority services, market monitoring and a self-governance model. (See Peak, PJM Pitch 'Marketplace for the West'.)

CAISO NEWS

PJM Chief Confident on Western Market Proposal

By Jason Fordney

SAN DIEGO — A joint effort between Peak Reliability and PJM offers Western industry players a chance to design their own market, one that will operate with more transparency than CAISO, PJM CEO Andy Ott said last week.

"The whole key here is the ability of the West to build up its own rules," Ott said.

The CEO added that PJM's expertise in coordinating markets and dealing with regional differences in the East will be a major asset in developing a Western market in partnership with Peak.

Having traveled west last week to attend a meeting of the Western Power Trading Forum, Ott sat down with *RTO Insider* to discuss the new Peak Reliability/PJM Connext market proposal. (See *Peak Touts 'Independent' Western Market Plan*.)

The partnership is galvanizing interest across the industry around a new Western market, but it comes amidst several other major recent developments shaking up the region.

Among them: competing efforts by CAISO to provide reliability coordinator (RC) services and extend its day-ahead capability into the Energy Imbalance Market (EIM). (See *'Horse is out of the Barn' for CAISO RC Effort* and *CAISO Plan Extends Day-Ahead Market to EIM*.)

PJM's executive spoke frankly about the shortcomings he sees in CAISO, including what he characterized as a relatively closed-door process for addressing market issues, compared with the more stakeholder-driven approach he envisions for the Peak market.

In California, "they have a discussion about a specific issue they are going to change, then they go in a room and make a decision, and they come out and they have a decision," Ott said. "It's not done that way everywhere."

Ott touted PJM's experience in operating a 13-state, multibillion-dollar energy market in the East. The RTO brings that experience to the effort, while Peak has the real-time reliability model of its territory already completed, he said.

Aside from the market proposals, Peak and CAISO are competing to provide NERC-certified RC services. Shortly after Peak and PJM announced their effort, CAISO dropped Peak as its RC and announced it would offer Western utilities RC services at a lower cost.

Peak CEO Marie Jordan, who also attended the WPTF event, noted that the only non-revocable notice of departure that the organization has received so far is from CAISO. Several Peak customers have announced they will leave, after CAISO issued its notice of withdrawal at the beginning of the year.

Late last month, the Bonneville Power Administration and Western Area Power Administration separately announced they have signed nonbinding notices signaling their intent to depart Peak by the end of 2019. BPA said it is exploring receiving RC services from CAISO, while WAPA is considering SPP and CAISO for some of its balancing authorities.

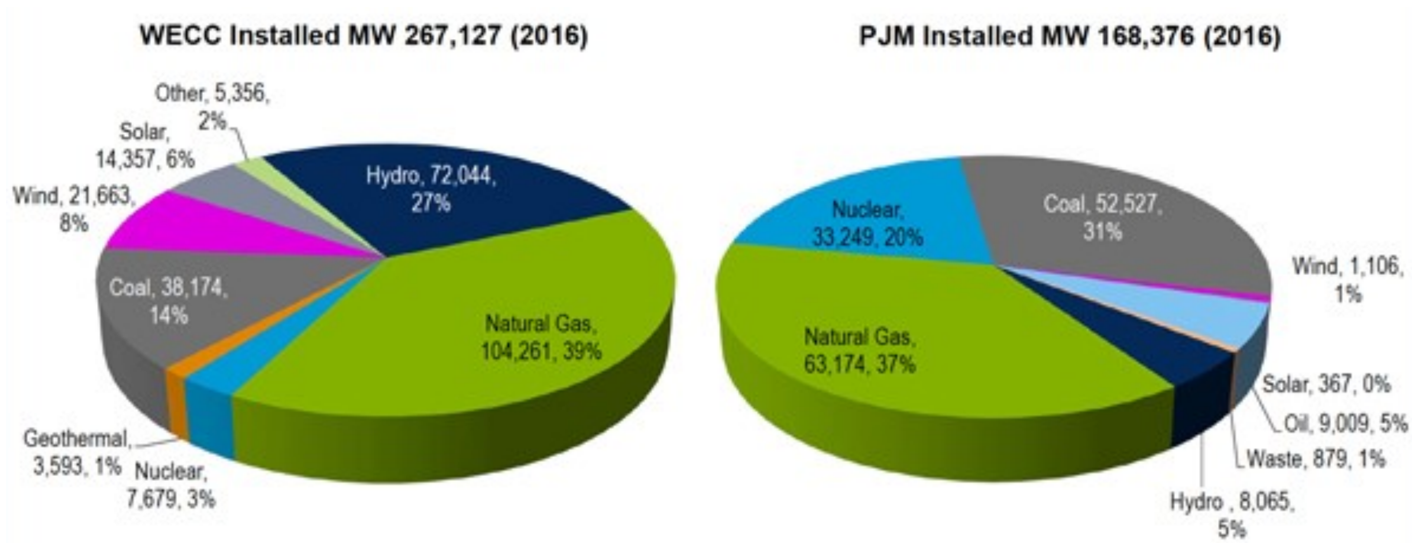
That move, along with a possibly rejuvenated effort to regionalize CAISO, represent other pieces of a shifting landscape. (See *Calif. Lawmakers Relaunch CAISO Regionalization*.)

Ott noted that the EIM was designed with the specific purpose of giving California a way to export renewable generation and get services back. The market benefits California customers, and he called outside regional participants "guests" in the market.

"I see the EIM, frankly, as a stopgap," Ott said. "It was created to solve a problem."

Ott said the business case for the market is being studied and is due to be issued March 30. Peak executives have publicly discussed the potential for the effort to evolve into a full RTO, something Ott says will depend on input from market participants.

"Our mindset is that if we put the PJM name on something, it's not going to fail. We cannot afford to let it fail," Ott said.



| *PJM Connext, Peak Reliability*

CAISO NEWS

Wildfire Costs Ignite Worry at CPUC, Legislature

By Jason Fordney

The Assembly Utilities and Energy Committee meets on Feb. 26. | *© RTO Insider*

SACRAMENTO, Calif. — California regulators and lawmakers are sounding the alarm over a possible decline in the financial and credit health of utilities stemming from wildfire risk and liability.

During an informational hearing Feb. 26, State Assembly members expressed concern over the finances of the state's investor-owned utilities because of their potential liability for a series of devastating wildfires in 2017.

Utilities and Energy Committee Vice Chair Jim Patterson (R) repeatedly asked California Public Utilities Commission President Michael Picker if he would describe the event as a "crisis," but Picker declined to use that term.

"I think we are headed toward bankruptcy for IOUs," Patterson said. "I really think this is a crisis and needs a crisis approach to it. I think we need to engage on this seriously."

"I see a continuum of constraints on utilities," Picker said, adding that declining credit ratings and financial health will affect their ability to invest in renewables and electric vehicles and to obtain insurance. "Certainly, they are going to find it harder to borrow."

In response to Patterson's question about what steps the state is taking in response, Picker said: "I assume that is one of the reasons we are having this conversation here today."

Pacific Gas and Electric CEO Geisha Williams has been outspoken about the issue of recovering costs related to wildfires. (See PG&E Vows Fight over Wildfire Cost Recovery.) She and Edison International CEO Pedro Pizarro have both said they will pursue the issue on "regulatory, legal and legislative" fronts. (See Edison International Presses Wildfire Cost Recovery.)

The third prong of that effort appeared to be underway Feb. 26, with discussions at the hearing indicating that utilities have been in contact with lawmakers and are mobilizing a strong effort on the liability and cost recovery issue.

Picker asked the legislature for more guidance on the principle of "inverse condemnation," the legal provision utilities use to recover wildfire costs. The principle states that "the costs of a public improvement benefiting the community should be spread among those benefited rather than allocated to a single member of the community."

Picker told *RTO Insider* that the CPUC's interpretation of inverse condemnation could lead to lengthy litigation, while the legislature can take quicker action.

Utility executives have criticized the commission's decision to deny San Diego Gas & Electric $379 million in cost recovery stemming from 2007 fires, rejecting the utility's inverse condemnation argument. (See Besieged CPUC Denies SDG&E Wildfire Recovery and Wildfires Color California PUC Utility Decisions.)

And the money at stake in that proceeding does not include additional potential liability for billions of dollars of costs from devastating fires that raged across California in 2017, the causes of which are still under state investigation.

Fitch Ratings on Feb. 26 downgraded PG&E to BBB+ and placed it on negative credit watch, while also putting Edison International on credit watch based on wildfire risks. In addition, utilities are facing multiple civil lawsuits over the fires, and analysts are also scrutinizing the credit ratings of California cities and localities, according to press reports.

Committee Chairman Chris Holden (D) told Picker he plans another conversation on inverse condemnation, as well as discussions on "new legislation that gives you new direction on what the good, the bad and the ugly of that represents."

"This will not be the first and last discussion we will have on this topic," Holden said, later adding that, "we are all trying to get our arms around the issue and how it has so many different components to it."

Holden said that when the legislative session ended last year, "this was not necessarily the topic I thought was going to take up all the energy for us." He is also leading a separate effort to spearhead the regionalization of CAISO. (See Calif. Lawmakers Relaunch CAISO Regionalization.)

Speaking at the hearing, CPUC Director of Safety Elizaveta Malashenko said preparedness and rapid response are keys to preventing disasters. Utilities are using new data collection technologies and practices to prevent fires, for example, by proactively de-energizing lines for risk reduction, a program the commission approved for SDG&E.

"When you are talking about wildfires, you are talking about a race against time," Malashenko said. The CPUC has increased its information sharing with the California Department of Forestry and Fire Protection, she said, and is investigating utility involvement in the 2017 fires. "It has been a very fruitful relationship," with Cal Fire better preparing for and responding to fires, she said.

CAISO News

Sempra Joins 'Three-Pronged' Wildfire Front

By Jason Fordney

Sempra Energy last week became the third California-based energy company to promise a "three-pronged" effort to recover costs related to wildfires and push back on liability for having potentially caused some of the state's deadly — and costly — fires.

During an earnings call, Sempra Energy CEO Debra Reed said that many factors are contributing to the worsening scope and spread of wildfires and that "it is irrational to place all of the burden strictly on utilities." She said a hearing held in the State Assembly on Feb. 26 on the wildfire issue was a favorable development. (See related story, *Wildfires Ignite Worries at CPUC, Legislature*, p.5.)

"There is a focus now on how to resolve this inverse condemnation issue now legislatively," she said, adding that the California Public Utilities Commission and State Legislature are working more closely on the issue. "I think there is going to be some movement in that area."

The "inverse condemnation" principle states that "the costs of a public improvement benefiting the community should be spread among those benefited rather than allocated to a single member of the community." California utilities have cited the principle in their attempts to recover the cost for repairing infrastructure damaged by wildfires.

The CPUC in late November denied $379 million in cost recovery to Sempra subsidiary San Diego Gas & Electric for wildfires that occurred in 2007, despite the company's use of the principle. (See *Besieged CPUC Denies SDG&E Wildfire Recovery*.) The state's other two investor-owned electric utilities, Pacific Gas and Electric and Edison International, have joined in requests for a rehearing of the CPUC decision.

"We will proceed expeditiously in the court" if the commission denies rehearing, Reed said last week. "I think that it is important to remember FERC approved full recovery for the same fires and same facts over four years ago."

In 2011, a portion of SDG&E's costs associated with the settlement of 2007 wildfire-related damage claims was identified as allocable to SDG&E's FERC jurisdiction assets, initially totaling $19.7 million, according to company statements. Sempra began discussing legal action last fall after the decision affected third-quarter financial results. (See *SDG&E's Wildfire Costs Undercut Sempra Profits*.)

Financial Results

In the fourth quarter of last year, Sempra recorded a loss of $501 million ($0.51/share), compared with earnings of $379 million in the fourth quarter of 2016. Excluding the impact of an $870 million expense in the fourth quarter related to last year's passage of the federal Tax Cuts and Jobs Act, a CPUC decision on 2007 wildfire cost recovery, and other factors, adjusted earnings were $389 million, compared with $383 million during the same period a year earlier, Sempra said.

"A portion of this income-tax expense relates to Sempra Energy's plans to repatriate approximately $1.6 billion of undistributed foreign earnings over the next five years," the company said.

The acquisition of Texas utility Oncor is another central issue for Sempra, and Reed noted the Public Utility Commission of Texas is due to vote on the deal as early as March 8. The U.S. Bankruptcy Court for the District of Delaware on Feb. 26 confirmed a reorganization plan for Oncor's parent company, Energy Future Holdings, including the California company's $9.45 billion acquisition of EFH and its 80% interest in Oncor. (See *Bankruptcy Court OKs Sempra-Oncor Deal*.)

Sempra also reached a revised settlement regarding retirement of the San Onofre Nuclear Generating Station and resolved legal claims on the Aliso Canyon natural gas leak. Sempra subsidiary Southern California Gas has resumed injections at the gas storage facility, where limited withdrawals have contributed to gas supply concerns in Southern California.

ERCOT NEWS

Overheard at the Infocast ERCOT Market Summit

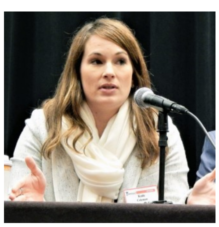
AUSTIN, Texas — Infocast's annual ERCOT Market Summit once again drew ISO staff, market participants and others for panel discussions on market reform, grid resiliency, resource adequacy, transmission constraints, wholesale price volatility, and integrating utility-scale solar power and battery storage.

Austin Energy's Barksdale English listens to ERCOT IMM Director Beth Garza make a point. | © *RTO Insider*

Participants Caution Against Market Changes Before Summer

Some of ERCOT's more vocal members urged caution as the market approaches a summer with projected record demand but with almost 8 GW less in generation after a wave of retirements and delays in planned projects.

The Public Utility Commission of Texas is considering withdrawing reliability unit commitments (RUCs) and reliability-must-run capacity from the operating reserve demand curve (ORDC), a real-time price adder that reflects the value of available reserves and is intended to incentivize resources to produce more energy and reserves. PUC staff said this would ensure that scarcity pricing is accurate and reflective of market dynamics. (See "Commissioners Delay Action on Removing RUCs from ORDC," *Texas PUC Briefs: Feb. 15, 2018*.)



But that would be a mistake, said **Katie Coleman**, legal counsel for Texas Industrial Energy Consumers. "Since 2012, we have spent a lot of time and effort designing the ORDC. We specifically discussed including RMR and RUC capacity. Ideally, the ORDC values should reflect the actual amount of reserves, which accurately reflects the likelihood of load shed. We did a bunch of other things instead, to try and put more money in the market," she said, referring to RUC's $1,500 price floor — "which is higher than any unit's actual cost" — and pricing RMR at the $9,000/MWh cap.

"We've built this machine, and we're about to have a summer where it's tested. Let's see how it goes, then come back, and see if there are areas that really need refinement."

"Part of the problem the last five years is we have never really defined what we are solving for from a reliability point of view," said Barksdale English, Austin Energy's interim chief of staff. "What is important to us? Is it short-term interval-to-interval reliability? Is it long-term five-, 10- or 15-year reliability? Until we figure out what we are solving for, having proposed solutions sort of seems like having the cart before the horse."

English jokingly referred to his "multiple personality disorder" as a generation-owning municipality competing in ERCOT's wholesale market. "I can get really excited about $9,000/MWh for wholesale generation, but then — oh my gosh — what about my consumers? Then, my City Council gets mad at me because my rates have to go up to cover that cost increase."

The Infocast ERCOT Market Summit audience from the speaker's podium. | © *RTO Insider*

Beth Garza, director of the ERCOT Independent Market Monitor, cautioned against blurring the difference between a load-shed event and a blackout. "That's a very important difference. Those loads are being paid to provide a service," she said.

"I fully expect many of those services will be called on this summer that have never been called on before. If those services are called on, they've been curtailed or are no longer consuming, but they're being paid for providing a service," Garza said.

"At what levels does ERCOT take emergency actions? When does load shed begin?" asked Strasburger & Price's **Mark Walker**, before answering his own question (when operating reserves reach 1,000 MW). "Hitting the offer cap with only 2,000 MW of available capacity left is sensible. If you look at actual prices when RUC resources are deployed by ERCOT under pressure from load, congestion and intermittent resources swings, the prices today really don't reflect that we're in an emergency situation or a serious reliability condition."

Role-playing Reveals Market Concerns

In a discussion on how low power prices are affecting the strategies of plant owners in ERCOT, summit organizers asked the panelists to role-play the different aspects of generation investment.

Federal Power Co. CEO Steve Gilliland, filled his natural role as a developer, and Tom Rose, CEO of Clean Energy Technology Association, played the investor. That left Cratylus Advisors' Mark Bruce, who represents Southern Cross Transmission in its bid to become the ISO's first DC tie operator, to play the regulator.

Asked what kind of signals the ORDC was

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ERCOT NEWS

Overheard at the Infocast ERCOT Market Summit

Continued from page 7

giving investors, Gilliland said, "It's not giving signals big enough and substantial enough."

"What drives the financier and developer is cash and cash flow," he said. "I don't believe that system is giving a clear enough signal for a long enough period of time that convinces me new generation is warranted. I don't believe it will be allowed to be a significant enough number. It's going to like moving the deck chairs around on the Titanic."

"As the regulator, that statement scares me because that ship didn't make it," Bruce deadpanned. "The ORDC was not intended to be a substitute for scarcity pricing. It is a construct intended to correct the anomalies in pricing that result from out-of-market actions of the grid operator.

"I applaud the Texas commission for resisting the call to pad the ORDC," Bruce continued. "That doesn't help the fundamentals. We've had significant periods of time where the system is overbuilt, and the prices will be, and should be, in the dirt during those periods. And that's the rub, a political rub. The economically optimal reserve margin is quite a bit smaller than the official, cushy planning reserve margin. We're about to live in the gap between the two, and the political leadership of the state is going to have to decide whether to let the market speak. The economics will reveal in themselves, and then the politics will play catch-up."

Rose, reminding the audience that he was playing the financier, said, "All this is fairly interesting. Existing generators are going to have a great Christmas this August, but I am going to hold off on new investment until we see how the summer works out.

Mark Bruce (left) plays a regulator, next to "financier" Tom Rose. | © RTO Insider

"I don't think anyone will argue we're moving into unchartered waters. That excites me. It might be a risk to some, but it's a reward to me. If there are involuntary disconnections or if prices go up or down, you're going to see a governmental reaction," Rose said. "Reliability the last 10 years has been taken for granted. I already hear people talking about reregulating the market. Mark and I know that's not going to happen. As he said, 'There is no Plan B.'"

Generators: ORDC Won't Incent New Generation

Generation owners in ERCOT debated the effectiveness of the ORDC, one of several pricing mechanisms the ISO says will help respond to tightening reserve margins this summer. (See *ERCOT: Tight Summer Margins No Cause for Alarm*.)

"The ORDC, which is a scarcity pricing mechanism, is absolutely working as designed," said Dynegy's **Bob Helton** during a panel discussion on resource adequacy. "The question is, is it getting us to where we want to be, which is reliability equilibrium and economic equilibrium?"

The Lower Colorado River Authority's **Randa Stephenson** said the ORDC should not be seen as a signal for additional generation development. Continued growth in wind generation is expected to pick up much of the slack for recent retirements of baseload generation, and while 2018 futures are trading around $140/MWh, the market has already considered the plant closings by Vistra Energy and others. (See *Vistra Energy to Close 2 More Coal Plants*.)

"Is there enough scarcity to signal a generation buildout? No, not even a peaker," Stephenson said. "If you look out into the future, the market knew Vistra was going to happen. Summer of 19, 20 prices didn't move up that much. I don't think the signals are out there to justify new build."

Stephenson said demand response mechanisms are having a greater effect on the market.

"As a generation owner … ORDC is icing on the cake," she said. "You see a lot of demand response looking at chasing those high-demand periods. You see a drop of 2,000 MW, and that takes away the scarcity prices you were anticipating."

"ORDC was never introduced, never is and never will be a resource adequacy tool," Helton said. "It's for scarcity pricing, a poor man's co-optimization. It does help with missing money and equilibrium in the market. The correct place for reserves to be is an economically optimal reserve margin. You will likely have load-shed events, but that's the economical thing to do."

Coauthor Behind Market Reform Report Highlights Tx Costs

Susan Pope, managing director of FTI Consulting's economic practice, told attendees during her keynote address that she and her coauthor on a report recommending ERCOT market reforms believe that the state's transmission planning policies have "materially" raised costs.

Pope said Texas' Competitive Renewable Energy Zones (CREZ) initiatives, a $7 billion program that built 2,800 miles of new transmission to deliver West Texas wind energy to the state's urban centers, was an out-of-market investment "not being made by at-risk investors who need to recover the full costs of their investment."

CREZ was part of more than $10 billion in transmission investments that have been added to total system costs over the past five years, she said.

"ERCOT regional transmission planning favors transmission for reliability problems, using very conservative assumptions for new generation," Pope said. "The analysis only includes resources that have committed to construction. Transmission investments will be identified and will pre-empt market-based generation solutions driven by energy-only prices, that could be alternatives to solving reliability problems.

"The over-investment in transmission is partly because of the long lead times to

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ERCOT NEWS

ERCOT: Tight Summer Margins No Cause for Alarm

By Tom Kleckner

ERCOT said Thursday it expects the recent retirement of coal-fired and aging units to result in tight operating reserves this summer — an unnerving proposition for some observers when the ISO is also projecting record-breaking peaks during the summer heat.

According to ERCOT's preliminary seasonal assessment of resource adequacy (SARA) for the summer (June-September), the grid operator expects a total resource capacity of 77.7 GW. That doesn't leave much wiggle room when the report also forecasts a summer peak load of almost 73 GW, which would break the 2016 record of 71.1 GW.

"The name of the game is performance," ERCOT Manager of Resource Adequacy Pete Warnken said during a media call, repeating a message CEO Bill Magness delivered to the ISO's Board of Directors last month. "We need to make sure all our resources are available and that we have situational awareness. If everyone is diligent about doing their job, we should be fine."

Warnken highlighted ERCOT's operating reserve demand curve (ORDC), a real-time price adder that reflects the value of available reserves, as one of several pricing mechanisms available for use this summer. He said the ISO will be "centrally testing" the ORDC for the first time this summer.

Dan Woodfin, ERCOT's senior director of system operations, joined with Warnken in explaining to anxious Texas media how emergency response and other ancillary services, demand response, the 1.2 GW of emergency capacity available over five DC ties, and the availability of generators that can switch between neighboring grids will help prevent rolling blackouts in a worst-case scenario.

"We certainly have the tools and processes in place," said Warnken, who also dismissed the likelihood of blackouts.

"In general, the whole market is set up in such a way that it encourages all generators to be online and resources to be available," Woodfin said. "During these tight conditions, when prices are higher, there are lots of economic incentives to reduce demand or produce power."

ERCOT said in its SARA announcement that the wholesale market provides "strong financial incentives" for generators to be available when demand rises and for retail electric providers to prepare for price fluctuations. It also raised the possibility of voluntary load reductions and injections of energy into the market by industrial facilities during peak demand.

In a somewhat unusual move, the Public Utility Commission of Texas, which oversees ERCOT, issued a statement following the SARA release, saying it continues to "closely monitor" this summer's supply and demand forecasts. It noted generation owners' decisions to retire large coal-fired power plants have "significantly reduced the excess supply of electricity" ERCOT has "enjoyed over the past five years."

"It is important to note that the ERCOT market is designed with a number of mechanisms and tools to incentivize increases in supply or temporary reductions in demand to maintain the reliability of the system," PUC spokesman Mike Hoke said, referring to the many different tools at the ISO's disposal.

ERCOT attributed the tightening operating reserves to increased load from the state's strong economy and the recent retirements. In a statement, Magness noted a series of monthly, winter and all-time peak demand records during recent years "as Texas' economy continues to grow at record pace."

"We expect high demand will continue this summer," he said.

The ISO's year-end Capacity, Demand and Reserves (CDR) report projected a 9.3% planning reserve margin for 2018, half of what it was in May and 4 percentage points below a 13.75% target ERCOT established for itself in 2010, following the wave of plant retirements last year. (See *ERCOT: Tightening Reserve Margins no Cause for Concern*.)

ERCOT said 3,800 MW in new generation resources began operating in 2017 and more than 14,000 MW of resources are planned to be in service by 2020.

The ISO also released its final assessment for the spring season (March-May), adjusting its spring peak forecast to 59.5 GW. It said it has sufficient generation on hand to meet demand.

Overheard at the Infocast ERCOT Market Summit

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build transmission," she said. "Those planning can end up with extremely expensive solutions to solve reliability. Continuing to build this transmission reduces energy prices because it resolves all the congestion before it has a significant effect on prices."

NRG Energy and Calpine commissioned Pope and William Hogan, research director of the Harvard Electricity Policy Group, to write a report assessing ERCOT's energy-only design. The report asserts that subsidized renewable resources, socialized

| © RTO Insider

transmission costs and the lack of local scarcity pricing have "exposed areas where there is a need for adjustments" to ERCOT's pricing rules. The Texas PUC held two workshops last year to discuss the report and other potential market reforms. (See *ERCOT, Regulators Discuss Need for Pricing Rule Changes*.)

During a discussion on transmission congestion constraints and how to address them, Brad Schwarz, Hunt Power's director of system planning, described the CREZ initiative's unintended consequences.

"CREZ was building transmission ahead of

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ERCOT NEWS

Overheard at the Infocast ERCOT Market Summit

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the generation, in the hopes the generation would come. It has happened," Schwarz said. Then came the state's oil and gas boom in recent years, he said.

"We would have been struggling to serve those loads without the CREZ," Schwarz said. "We were able to serve more oil and gas load and bring more economic development to the state of Texas. You never really undervalue a transmission line. Once it's out there, it finds value."

Energy Storage Offers Solution to Congestion Issues

Kip Fox didn't hide his disappointment over Texas regulators' recent rejection of an American Electric Power request to connect a pair of utility-scale battery facilities to the ERCOT grid. AEP's application ran into opposition from consumer organizations and market participants who argued that allowing the assets to be included in the regulatory base would harm competition. (See "Staff Opens Battery-Storage Rulemaking," *Texas PUC Briefs: Feb. 15, 2018*.)

"We had an alternative to building a long distribution line. It was a $1.6 million solution to a $12 million problem," said Fox, president of Electric Transmission Texas, a joint venture between AEP and Berkshire Hathaway Energy subsidiaries. "Unfortunately, since those [applications] were denied, without prejudice, we're kind of back to square one."

He said with batteries' ability to provide frequency support and resolve overloading problems, "it makes more sense to run a battery eight to 10 times a year, rather than building a line." Fox suggested Fluence Energy's use of a portable battery in downtown Indianapolis presents a possible solution to congestion issues.

"We would like to move a battery around and solve that problem," he said. "When the congestion is gone in five years because a transmission line hasn't been built, we will have saved the ratepayers a lot of money."

Tim Ash, Fluence's market director for the eastern U.S., said other RTOs are wrestling with the same concerns over battery storage ownership and its effect on markets.

"There's a much, much bigger market for energy storage," Ash said. "It solves a reliability issue, which occurs maybe 10 times a year. The economic benefits are there today. The question is how to get the rules to unlock those benefits."

FERC last month directed RTOs and ISOs to allow energy storage resources full access to their markets, an order that does not apply to ERCOT (RM16-23). (See *FERC Rules to Boost Storage Role in Markets*.) Asked if FERC's directive might influence the PUC, which regulates ERCOT, to follow suit, Fox said, "Hell, yeah!"

"I've seen many times where the commission defaults to where FERC opens up the rules," Fox said. "I find those rules are sometimes a little behind, sometimes a little ahead. There will be some pressure at all levels of the [state] government."

Jack Farley, CEO of Apex Compressed Air Energy Storage, pointed to a 2012 PUC order that allows energy storage resources in ERCOT to pay wholesale prices for recharging, with no retail or transmission or distribution fees. "The energy market averages 40,000 MW and the ancillary services market is about 5,000 MW. In terms of participating in ERCOT energy and ancillary service products, I don't think there are barriers today for energy storage resources," he said.

"We will see energy storage adopted early," said a more optimistic **John Bonnin**, vice president of energy supply and market operations for San Antonio's CPS Energy. "As the technology improves, we will see it displace other applications in other parts of the market. If we meet again in five years, every one of us around here will have some sort of storage on their system. We all have to get smarter about the effect all that capacity will have on pricing, fuel and dispatch. It's going to be disruptive."

Developers See Bright Future for Texas Solar

Spivey Paup (left) and Shalini Ramanathan | © *RTO Insider*

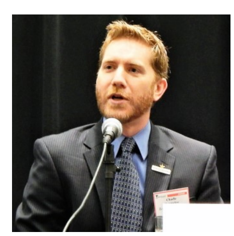
A panel of solar developers gave high marks to the Texas market, which could see up to 8 GW of solar growth over the next few years.

"Texas is attractive because of low pricing. Wind is the headline, but at the same time, if the load continues to grow, we can make the case that there's a match there for solar too," said Andrew Fay, origination manager for First Solar.

Shalini Ramanathan, vice president of origination for RES Americas, said price pressure "is the reason we're seeing so much development in West Texas and with large projects. If we can be competitive, we can do more 20-MW projects in other parts of the state. I think there's a bias to larger West Texas solar."

Spivey Paup, Recurrent Energy's development director, said even West Texas, with its oil and gas infrastructure, can pose challenges.

"But once you get out of the Permian Basin, that complication goes away," Paup said, referring to Texas' rich petroleum fields. "We need to find a balance between strong resources and development complications. Renewables and solar were born and bred in California, but we can blow them up to scale and send California packing."



Charlie Hemmeline, executive director of the Texas Solar Power Association,

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said current rules have resulted in "steady interest" in sun-powered generation in the state.

"We're not going to ask for new polices or mandates or incentives," he said. "We want it to work the way Texas wants it to work. 'Don't do anything bad to us' is the primary policy ask."

EVs, With or Without Drivers, are Coming

During a discussion of changing perspectives among end-use customers, Rob Threlkeld, General Motors' global manager for renewable energy, noted he had driven from Detroit to Lansing, Mich., without once touching the steering wheel of his Cadillac CT6, thanks to its Super Cruise semi-autonomous driver-assistance system. The car comes in a plug-in version in addition to four- and six-cylinder engine models.

"In a year, the driver will touch the steering wheel much less," Threlkeld predicted.

He had a believer in Champion Energy Services CEO Michael Sullivan, who owns a Tesla. He said the more mainstream CT6, which starts at about $85,300, will be more broadly available and easier to purchase than the special-order Tesla models.

Champion Energy's Michael Sullivan (left) entertains GM's Rob Threlkeld with his quips. | © RTO Insider

"When you order Tesla, it's like ordering an Italian shoe from a cobbler in Milan," he said.

Both Threlkeld and Sullivan agreed that electric vehicles pose a sea change for the electric industry.

"We have been working closely with a lot of utilities, especially those progressive ones that are really interested in this space. It's load growth, and that interests them," Threlkeld said.

"If the projections are right, my teenage kids will never drive an internal-combustion car," Sullivan said. "If everybody's driving an electric car, that's a major change to the industry, especially if somebody can capture storage in a really dense way."

— Tom Kleckner

RTO Insider's Tom Kleckner moderates a panel on ERCOT wholesale price volatility. Panelists include (left to right) Skylar Resources' Gerald Balboa, Citigroup's Yashar Barut, ERCOT's Kenan Ogelman and Engie Resources' Andrew Elliott. | *© RTO Insider*

ISO-NE News

FERC OKs New ISO-NE Bilateral Capacity Trades

By Michael Kuser

FERC on Wednesday accepted ISO-NE's proposed new capacity bilateral transaction and a revised materiality threshold for determining whether a resource can satisfy its capacity supply obligation (CSO) (ER18-455).

The grid operator proposed the annual reconfiguration transaction (ART) to replace the capacity market's existing bilateral contracting mechanism, the CSO bilateral. The RTO said the change was needed to accommodate its transition to marginal reliability impact-based demand curves (MRI), which are based on the expected improvement in reliability from adding incremental capacity.

The commission's Feb. 28 order said that the ART will give resources looking to replace their CSO through a bilateral contract more flexibility. "The ART mechanism will accommodate even or uneven exchanges within the same zone or across constrained zone boundaries, even where exchanges previously were prohibited, while accounting for the actual net impact on reliability in a manner that does not disadvantage suppliers or consumers," the commission said.

FERC also agreed to ISO-NE's proposal to change how it determines when to submit demand bids in the third Annual Reconfiguration Auction (ARA) for resources that have a significant decrease in capacity. The RTO said its previous threshold — 20% of its CSO or 40 MW, whichever is lower — produced outcomes that focus on relatively small deficiencies and ignore relatively large deficiencies. For example, a 35-MW deficiency from a 100-MW resource would be subject to the RTO's mandatory demand bid rule, while the same deficiency from a 200-MW resource would be exempt.

Under the new rules, the RTO will intervene when a resource's capacity decreases by 10 MW, or 10% (but at least 2 MW), whichever is lower.

The commission dismissed FirstLight Power Resources' request to eliminate the minimum 2-MW floor for the threshold. "We do not find any evidence that the proposed changes will result in undue discrimination among resources or compromise the integrity of the capacity markets, as FirstLight claims," it said. The proposed thresholds "reasonably balance the impact on large and small resources, while reducing ISO-NE's administrative burden."

FERC also rejected a request from New England generators Exelon, CPV Towantic and NRG Power Marketing that the mandatory demand bid changes take effect in Forward Capacity Auction 9, rather than FCA 11.

Because it found the "proposal, including its implementation date, to be just and reasonable, we need not consider whether an alternative proposal is also just and reasonable," the commission said.

There was no evidence that the new threshold will undermine the integrity of the capacity market, the commission said. "For all resources, regardless of the significant decrease threshold, the general obligations associated with having a CSO continue to apply." The existing thresholds have not undermined the integrity of the capacity market or sent a signal that it is appropriate to intentionally overstate a resource's capacity values, it said.

"We find it is reasonable to expect that the revised rules, which ISO-NE expects to affect a similar amount of capacity as the existing rules, likewise would not undermine the integrity of the market," the commission said.

ISO-NE News

Overheard at ISO-NE's Consumer Liaison Group Meeting

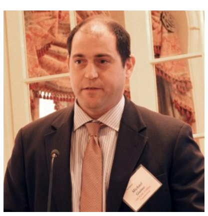
NEW CASTLE, N.H. — More than 100 people gathered with ISO-NE's Consumer Liaison Group (CLG) at the historic Wentworth by the Sea hotel to discuss the rapid changes overtaking New England's electricity market.

The CLG holds quarterly meetings around the region to provide a chance for residents, state officials and energy experts to learn more about the grid operator.

CLG Chair **Rebecca Tepper**, chief of the energy and telecommunications division in the Massachusetts attorney general's office, said the group is "thinking about additional opportunities for members of the CLG to talk directly to ISO New England professionals and staff, just so there's more direct communication available."

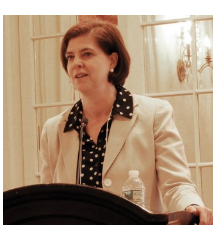
Here's more of what we heard at the CLG's most recent meeting.

From Consumer Boon to Market Boom



New Hampshire Public Utilities Commissioner **Michael Giaimo** said that New England's market restructuring has benefited consumers.

"No longer can a utility build a generation facility solely on the backs of ratepayers," Giaimo said. "The system of captive ratepayers being susceptible to stranded costs has been replaced by developers and their shareholders bearing the risks and the rewards associated with building, operating and maintaining a generation facility."



Anne George, ISO-NE vice president for external affairs, said the RTO's 2017 average wholesale energy prices were the second lowest since 2003, while last month's Forward Capacity Auction 12 marked the third consecutive decline in clearing prices. (See *ISO-NE Capacity Prices Hit 5-Year Low*.)

George reiterated the RTO's concerns about fuel security, a challenge brought home during two bitter cold weeks around New Year's Day when New England generators burned through nearly 2 million barrels of oil, more than twice the amount used by the region's power plants during all of 2016. (See related story, *Van Welie: ISO-NE in 'Race' to Replace Retirements*, p.1.)

Giaimo noted that the cold snap saw the value of the region's energy transactions surge to about $1.1 billion during the first three weeks of January, equal to 25% of the entire energy market value in 2015. (See *FERC, RTOs: Grid Performed Better in Jan. Cold Snap vs. 2014*.)

Markets Misalignment

Jonathan Peress, director of energy market policy at the Environmental Defense Fund, said the Northeastern power price spike observed Jan. 5 was not driven by New England gas pipeline constraints but by New York City power demand, which was symptomatic of a misalignment between gas and electric pricing.

"Very high LNG sendout kept Algonquin [gas hub] prices lower than would otherwise have been the case on Jan. 5," Peress said. "LNG was the key resource that allowed consistent access to gas."

The value of gas supply and pipeline delivery service fluctuates over the course of the day, but the gas market primarily relies on a single daily index price. Non-ratable takes are valuable to generators, but the variable flow and pipeline flexibility service is not priced, he said.

"It's really not good to be relying on 50-year-old oil steam boilers for our reliability in New England," Peress said. "I used to manage some of them — not pretty."

New Hampshire Sen. Andy Sanborn (R) said "virtually every woe you have, when it comes to your ability to run your company and energy policy, actually solely starts at the legislature."

The legislature controls the energy conversation, and discussion ends up being a debate between left and right, Sanborn said, when the region has systemic problems.

"It is specifically the legislature that determines whether we're going to let that market run freely, all the way from our ability to sign off on long-term plan purchase contracts ... to what percentage of our business needs to be renewable or non-renewable, and whether or not we are allowing companies to bring gas in or bring power down," Sanborn said.

Market-Based Solutions

Carl Gustin, a communications strategist with consultancy Salient Point, brought a historical perspective to the discussion by recalling how the 1978 Power Plant and Industrial Fuel Use Act banned the use of natural gas by power plants.

The first energy-efficiency measures elicited disbelief among utility executives who could not envision "un-selling" their product.

"We called it conservation back then," Gustin said.

But now: "You've got renewables coming up and coming on quickly and you've got to manage that system both for voltage and for reliability," Gustin said. "You've got a big problem in front of you."

Tanya Bodell, executive director of consultancy Energyzt, said that, coming from the Chicago school of economics, she always favors market-based solutions.

"Right now, there's not an incentive through the price signal for most customers to adjust their consumption, so we're really not tapping into the demand response," Bodell said. "And customers can make money — those who are able to make those adjustments. I would say that's a market solution."

Pricing carbon is another market-based solution, she said.

"If you put a price on carbon, the cost of the oil-fueled units will become more expensive and other alternatives, LNG for example, can come in and help to solve that. We saw LNG flowing into New York. If the price signal is there, it will come."

— Michael Kuser

ISO-NE NEWS

Van Welie: ISO-NE in 'Race' to Replace Retirements

Continued from page 1

In January, the RTO released an Operational Fuel-Security Analysis that examined 23 fuel-mix scenarios and concluded that inadequate fuel supplies would cause power shortages under 19 of the scenarios by winter 2024-25. Those shortages would require emergency actions such as voluntary energy conservation and involuntary load shedding, or rolling blackouts. (See *Report: Fuel Security Key Risk for New England Grid*.)

Smoker of a Cold Snap

During two weeks of bitter cold surrounding New Year's Day, New England generators burned through nearly 2 million barrels of oil, more than twice the amount used by the region's power plants during all of 2016, van Welie said.

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

Contributions from other types of generators were crucial during the cold snap, according to the RTO's analysis.

"For instance, electricity produced by the Millstone nuclear station during the cold spell is equivalent to what could be produced by about 880,000 barrels of oil, and the power from the Mystic 8 and 9 units in Boston, which are fueled by LNG from the nearby Distrigas import facility, was the equivalent of more than 360,000 barrels of oil," van Welie said.

High oil consumption means higher emissions. At the end of the cold snap, just one week into 2018, several oil-fired generators were already nearing their annual emissions limits, he said.

"The region can pay the bill for its fuel-security risks periodically, in spiking wintertime prices and potential energy shortages, or the region can pay the costs proactively and avoid reliability risks by investing in infrastructure, firm fuel contracts and other incentives," van Welie said.

That new infrastructure could include further efficiency measures, transmission lines, renewable energy resources, storage facilities for liquid fossil fuels and gas pipeline infrastructure.

"Clearly, as one makes some of these infrastructure investments, you begin to lower the costs of the reliability services that the ISO seeks to procure," van Welie said.

As oil resources retire — including those solely fueled by oil — the grid becomes more dependent on imported LNG or dual fueling, he said.

"I think the dual fueling becomes more constrained given the emissions constraints in the region," van Welie said. The solution is "really a combination of electricity imports from neighboring regions and LNG as the balancing fuels as we put more and more renewables on the system, and that's assuming we make no more investment in the gas infrastructure."

Since 2000, the share of oil- and coal-fired generation in the region's power production has fallen from 40% to less than 10%, while natural gas has risen from 15% to about 50%, he said.

Wind and CASPR

Solar has "exploded" in New England, largely because of state incentives, van Welie said, growing from 250 MW to 2,400 MW in just five years. Most resources are located in more than 130,000 small installations on homes or businesses.

And last year, wind power for the first time surpassed natural gas for the volume of generation seeking interconnection in the RTO's queue. About 4,000 MW of that proposed wind would be located offshore of Massachusetts, with most of the remaining 4,500 MW onshore in Maine. (See *Mass. Receives Three OSW Proposals, Including Storage, Tx*.)

As the amount of wind and solar power continues to grow, in part driven by state policies, the RTO in January proposed a new two-stage capacity auction, Competitive Auctions with Sponsored Policy Resources

(CASPR), to enable its Forward Capacity Market to accommodate state policy-sponsored, clean energy resources in the wholesale market, while maintaining a viable economic model for existing power plants. (See *ISO-NE Defends CASPR Against Protests*.)

CASPR, which the RTO proposes to implement on June 1, would "fully integrate demand response resources … into the competitive energy and reserves markets, where they can compete with conventional generators," van Welie said. "ISO New England will be the first in the country to fully integrate DR into energy dispatch, building on its longstanding commitment to DR."

The most effective way to achieve the states' environmental objectives is to put an appropriately high price on carbon, van Welie said, because it would spur investment in cleaner resources.

"That could be the most efficient way of doing it through a wholesale market mechanism," van Welie said. "It would allow us to avoid making this CASPR proposal that we recently filed at FERC. But we do understand that's not the preferred choice of the states, and we respect that, and hence we have come up with this method for accommodating what they're doing through above-market contracts."

MISO NEWS

MISO Storage Task Force Talks FERC Order 841

By Amanda Durish Cook

MISO's Energy Storage Task Force has been left wondering if it will help shape the RTO's response to FERC's sweeping storage participation order issued last month.

The task force has yet to learn its role in working with MISO staff to craft market rules to comply with Order 841, which directs RTOs and ISOs to remove barriers preventing storage from participating in energy, capacity and ancillary service markets. RTOs will be given 270 days from publication in the *Federal Register* to file revised tariff language with FERC outlining a participation model and another year to implement the changes.

"Frankly, we don't know how this will affect the task force," task force Chair John Fernandes said during a March 1 meeting. He added that MISO's Steering Committee would have to issue a directive for the task force to begin specifically considering Order 841 compliance. Until then, the group will continue to examine what MISO rules might need to be revised or added to enable storage to participate in markets. (See *MISO Staff, Stakeholders Envision Expanded Storage Participation*.) Wisconsin Public Service's Chris Plante pointed out that MISO doesn't necessarily run compliance filings by stakeholders before they are filed with FERC.

The RTO says it will use stakeholder input on the compliance filing, although it's not yet clear how extensively stakeholders or the task force will guide the process.

"MISO is actively working on the Order 841 compliance filing though it has not yet appeared in the *Federal Register*," spokesman Mark Brown said. "While the compliance obligation lies with MISO, MISO intends to leverage its stakeholder groups to get input from stakeholders as it works through the issues as identified in the filing. This includes the Energy Storage Task Force and other stakeholder subcommittees."

Fernandes said FERC's order defines storage as resources that can inject into the grid, making them eligible for make-whole payments and qualification as capacity resources.

"FERC was clear that they don't want to change market rules to accommodate storage, but they want it to be able to participate," Fernandes said. "The idea of this order is to allow storage to participate in markets considering their operating characteristics."

Energy Storage Association Vice President of Policy Jason Burwen said his organization is still reviewing the order to determine which storage directives are firm and which might allow more latitude.

MISO Director of Market Engineering Kim Sperry reminded stakeholders that there's a 30-day window to ask FERC for clarification on the order.

Fernandes said it's unlikely FERC's rule will become effective within 90 days without delays.

"The effective date in the *Federal Register* assumes that all six markets say, 'great,' and have zero questions. The odds of that happening are between zero and zero," Fernandes said.

He said that while Order 841 did not address storage acting as transmission, the task force will nevertheless continue to discuss MISO valuing "storage-as-wires."

"We are going to have to go outside the bounds of Order 841 to talk about storage as transmission," he said.

Dave Johnston, a staffer with the Indiana Utility Regulatory Commission, said he was troubled the order seems to allow distributed assets into the wholesale market, seemingly over the heads of state regulators.

"This may impede on state law," Johnston said.

"I don't think your concern is overblown," Fernandes said. "I think FERC very firmly planted its flag and said the wholesale market is our sandbox."

However, Fernandes said he didn't think FERC intended to trample state jurisdiction. Indianapolis Power and Light's Lin Franks said she thought FERC was simply trying to include distributed assets within the definition of storage resources.

"I think, to me, FERC did exactly what it's supposed to do; it provided an endpoint and left it up to the RTOs how to get there, recognizing how unique each of these markets are," Fernandes said.

FERC has ordered a technical conference for April 10-11 on whether it should treat aggregated distributed energy resources the same as it directed for storage in Order 841. (See *FERC Rules to Boost Storage Role in Markets*.)

IPL Complaint

Some stakeholders asked if the Order 841 compliance filing would affect the outcome of IPL's FERC complaint against MISO's restrictive storage participation rules, which prompted the RTO to propose revising its Tariff to include a stored energy resource type II to facilitate participation (ER17-1376). (See *MISO Rules Must Bend for Storage, Stakeholders Say*.) MISO planned for the new resource to be in use while it waited for a more comprehensive FERC storage rule, and some stakeholders are wondering if the filing would now become inconsequential.

MISO legal staff at the meeting said FERC must decide between accepting, accepting in part or rejecting its Tariff filing, or rendering the filing moot in favor of waiting for its Order 841 compliance filing.

Grand Ridge battery storage facility | *BYD*

MISO NEWS

FERC Vacates, Upholds MISO Resource Adequacy Rules

By Amanda Durish Cook

In two orders issued on the same day last week, FERC both vacated and reinstated MISO's entire resource adequacy construct, ultimately leaving the RTO's current capacity auction format — and past auction results — undisturbed.

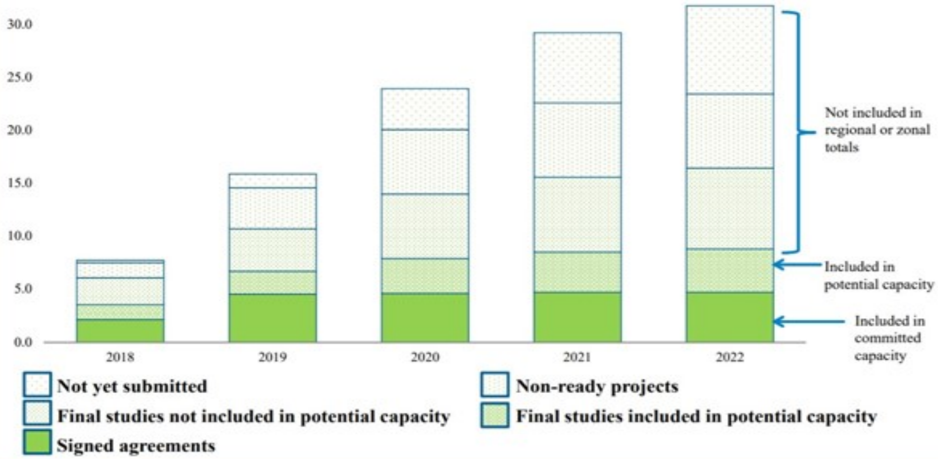
FERC's two Feb. 28 decisions concurrently reversed its 2012 acceptance of MISO's resource adequacy rules (ER11-4081) and accepted the RTO's refiling of the rules (ER18-462).

To protect its market from "potential disruptions," MISO in December pre-emptively refiled its entire resource adequacy construct in response to the D.C. Circuit of Appeals' ruling that FERC overstepped its "passive and reactive" role when it prescribed revisions to PJM's minimum offer price rule. MISO was concerned about the impact of that decision on some of the resource adequacy rules that had been guided by FERC's recommendations. (See *MISO Seeks FERC Reapproval to Keep RA Rules Intact*.)

Following the PJM decision, the D.C. Circuit granted FERC a voluntary remand to once again consider MISO's 2011 market revisions.

In the order on remand, FERC said in light of the court's PJM decision, "the modifications set out in the [resource adequacy orders] could be considered to be major modifications to MISO's 2011 filing. Accordingly, because we cannot find MISO's 2011 filing to be just and reasonable without our modifications, we reverse the commission's conditional acceptance of MISO 2011 filing, and we reject MISO's 2011 filing in its entirety."

FERC at that time rejected MISO's proposed mandatory auction requirement and minimum offer price rule and ordered the RTO to phase out grandmother agreement provisions after the 2014/15 auction. Taken together, the revisions "would likely be considered to result in an 'entirely different rate design' than both MISO's proposal and MISO's prior rate scheme," FERC said, acknowledging it had exceeded its authority under the Federal Power Act, "notwithstanding that MISO consented to those revisions."



Potential generation additions (GW) | *MISO*

No Auction Do-Overs

However, FERC found that rerunning the last five years of MISO's Planning Resource Auction under the pre-2011 monthly auction rules would be infeasible and unnecessary.

"Such a remedy would be extremely complex, subject to controversy and further litigation, and cause significant disruptions and burdens," the commission said. "It would be highly difficult, if not impossible, for the commission or MISO to reasonably provide retroactive relief, by rerunning the auction for the 2013/14 planning year through the present."

The commission then addressed MISO's refiling, determining that the RTO's current auction format should remain unchanged.

MISO Independent Market Monitor David Patton used the refiling as an opportunity to again urge FERC to order the RTO to employ a sloped demand curve in its capacity auction in order to produce more efficient pricing. (See *MISO Monitor to FERC: Order Sloped Demand Curve*.)

But the commission said MISO's vertical curve was just and reasonable, noting that 90% of load is served by vertically integrated utilities. It said that, at any rate, pricing takes a backseat to the main objective: maintaining reliability.

"We … disagree with the Market Monitor's contention that a vertical demand curve leads to prices that are not just and reasonable by failing to recognize the diminishing marginal benefits of excess capacity. MISO's resource adequacy construct was developed to ensure that [load-serving entities] in MISO acquired sufficient capacity each year to maintain the one-day-in-10-year reliability standard. Although certain constructs may value capacity beyond that amount, doing so is not essential to MISO's construct fulfilling this principal objective," the commission said.

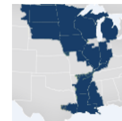
MISO maintains that its vertical demand curve and its annual resource adequacy survey with the Organization of MISO States "combine to provide just and reasonable signals."

The commission also dismissed several other protests from stakeholders, including complaints that supply offers above $25/MW-day (about 10% of MISO's cost of new entry) are read as an attempt to exercise market power under current capacity auction rules and that LSEs participated in price suppression in the 2017/18 auction.

FERC instead said that 2017/18's low clearing price of $1.50/MW-day should be taken as the simple effect of supply and demand in MISO.

"The low capacity prices, where they have arisen in MISO, accurately reflect MISO's capacity surplus. The fact that prices have not signaled to independent generators a need to build, retrofit or even simply maintain existing resources is more indicative of a well-functioning capacity procurement construct than it is of an unjust and unreasonable construct," the commission said.

MISO NEWS



FERC Approves MISO Presque Isle Refund Calculation

FERC last week accepted MISO's plan to allocate Michigan ratepayers $24.6 million in refunds for overcharges stemming from RTO-ordered system support resource agreements imposed on a Wisconsin Electric Power Co. coal-fired plant.

The commission directed MISO to execute the refunds — which include interest — over a 10-month period beginning Feb. 28 (ER14-2952-005).

FERC ruled in late October that WEPCo overcharged ratepayers on Michigan's Upper Peninsula by almost $23 million for agreements that kept the 344-MW Presque Isle coal plant in Marquette, Mich., running in 2014 and early 2015 for reliability purposes. The commission directed MISO to calculate the refunds over the RTO's objections that it did not provide clear guidance on how to do that. (See *$23 Million Owed to Ratepayers in Presque Isle SSR Case*.)

Constellation Energy Group received the largest refund at $13.6 million, followed by Cloverland Electric Cooperative ($6.3 million), Upper Peninsula Power Co. ($4.9 million) and the city of Escanaba ($1.1 million). WPPI Energy must refund $3 million because SSR costs raised its wholesale rates. Of the 17 load-serving entities involved, six were found to owe money. MISO redacted the monthly refund report in a public version of its filing because it would reveal "insight into monthly load patterns," according to the RTO.

MISO had proposed to invoice the resettlements as a lump sum on Dec. 19, instead of over the original 14-month timeline. FERC determined that a 10-month distribution was more appropriate because it corresponded with the established April 3, 2014, refund effective date through the Jan. 31, 2015, termination of Presque Isle's second SSR agreement.

— Amanda Durish Cook

Presque Isle | *WEPCo*

MISO Wins Delay on 5-Minute Settlement Rollout

MISO on Wednesday secured another four months to implement mandatory five-minute market settlements, providing its staff more time to roll out new software designed to manage the process.

FERC granted MISO's request to delay implementation from March 1 to July 1 after the RTO said it requires "more time to develop and test the software, after which market participants need a minimum of three months to make corresponding adjustments to their own software and reporting systems" (ER18-314).

The decision marks the second time the commission has extended the deadline for instituting five-minute settlements, required under FERC Order 825. MISO last May won an initial extension from Jan. 11 to March 1, but late last year multiple stakeholders noted that delays in replacing the RTO's overall settlements system would result in members rushing to adapt their own systems to accommodate the new process. (See "MISO Asks for 5-Minute Settlement Delay," *8 Projects Set for 2018 MISO Market Roadmap*.)

FERC determined that MISO's request for more time was made in good faith and was necessary for software testing.

"We find that good cause exists to grant this extension because of the importance of ensuring that software and testing requirements are met for both MISO and its market participants. … This extension will facilitate a smoother and more effective implementation of five-minute settlements in MISO," the commission said.

In February, MISO staff said the RTO is still on track for fully functional testing with stakeholders beginning April 1, with the new settlements computer system fully implemented by April 16.

— Amanda Durish Cook

FERC to Examine 2 MISO Generators' Reactive Rates

FERC last week instituted proceedings to examine the reactive rate schedules of two MISO generating facilities: the 471-MW RockGen natural gas plant in Christiana, Wisc., (ER13-1589) and the 555-MW Carville steam and gas cogeneration facility in southeastern Louisiana (ER18-554).

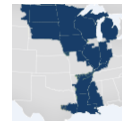
The commission opened a Section 206 proceeding in a new docket (EL18-51) to re-evaluate RockGen's reactive rates as a result of parent company Calpine's proposed acquisition by an investor group led by Energy Capital Partners. FERC had accepted RockGen's $700,000 annual reactive service revenue requirement in 2013.

The owner of the Carville plant, LS Power Development, asked on Dec. 28 for an annual reactive power revenue requirement of more than $1.1 million.

FERC said Carville didn't provide proper evidence for multiple factors behind its revenue requirement: "Several components of Carville's revenue requirement are not adequately supported, including, but not limited to, Carville's fixed [operations and maintenance] expenses included in the fixed charge rate, the Carville facility's production plant cost components and the accessory electric equipment allocator. Additionally, Carville utilized an outdated federal tax rate and incorrectly applied … methodology in calculating the Carville facility's balance of production plant cost," the commission said in its Feb. 28 order.

— Amanda Durish Cook

MISO News



FERC Rejects MISO Pseudo-Tie Pro Forma

By Amanda Durish Cook

FERC last week rejected MISO's proposed *pro forma* agreement for pseudo-tying generation into PJM, saying the rules around termination were too broad.

"Although we believe that a *pro forma* pseudo-tie agreement is a beneficial instrument to promote uniformity, transparency and certainty as to what the responsibilities and obligations are with respect to the increasing interest to use pseudo-tie arrangements, we find that parts of the MISO agreement have not been shown to be just and reasonable," FERC said in its order (ER17-1061).

The commission encouraged MISO to file a revised version.

In rejecting the agreement, FERC said MISO's proposed termination provisions did not align with already accepted revisions to the MISO-PJM joint operating agreement. (See *FERC OKs Change to MISO, PJM Pseudo-Tie Rules*.) The agreement was unclear about the meaning and consequences of a suspension, FERC said.

"The MISO agreement does not detail what happens to resources under suspension, how a resource may seek to resume normal operations, which balancing authority retains operational control of the resource while it is under suspension, or how a resource under suspension may be terminated," FERC said.

The commission called the termination provisions "vague and open-ended." While MISO proposed to give itself authority to "make all final determinations whether to implement or terminate [a] pseudo-tie," FERC interpreted that language as granting the RTO the ability to terminate a pseudo-tie for any reason, provided it satisfied the six-months' notice requirement.

The proposed agreement would have allowed MISO to suspend and terminate pseudo-ties if resource owners failed to provide real-time measurement values in a timely manner; if the generation-to-load distribution factor between MISO and PJM was not within 2%; and if a partially pseudo-tied resource injected more energy into MISO than the modeled limit.

MISO also proposed that a pseudo-tie maintain firm transmission service from source to sink for the life of the pseudo-tie, and that it could terminate a pseudo-tie if reliability is threatened, with no notice beyond compliance with NERC standards. However, the RTO proposed that its *pro forma* requirements would not be retroactively applied to existing pseudo-ties, provided that those existing pseudo-ties aren't modified. In the event of a modification, MISO would restudy the pseudo-tie.

The rejected proposal was the subject of a deficiency letter last year in which FERC questioned under what circumstances MISO could revoke a pseudo-tie. (See *MISO, PJM Respond to FERC's Pseudo-Tie Questions*.)

FERC's ruling also dismissed as moot a protest and rehearing request by the Illinois Municipal Electric Agency, which had complained that MISO's proposal threatened the vested rights of market participants with long-term historic generation and transmission rights to serve load. The agency argued that MISO could terminate its long-term, fixed transmission rights at any time and that the proposed 2% distribution load provision "suffers from a lack of transparency because modeling upon which this provision is based is complex and, for the most part, confidential" between PJM and MISO.

IMEA also contended the agreement should be between MISO, PJM and the pseudo-tie owner, rather than just MISO and the owner.

MISO Reaction; IMM Reliability Suspicions

MISO briefly addressed FERC's rejection during a Feb. 28 MISO-PJM Joint and Common Market meeting, saying it intends to file again.

Kevin Vannoy | © *RTO Insider*

"MISO feels that the circumstances surrounding that agreement still exist, and the agreement is still needed," Director of Market Design Kevin Vannoy told meeting attendees. The RTO plans to return to the Reliability Subcommittee sometime in spring to revise the agreement with stakeholders.

MISO and PJM staff at the meeting also noted they have reliably administered a considerable increase in pseudo-ties since the start of the 2016/17 planning year. MISO says its total pseudo-tied volume increased from 1,966 MW in June 2015 to 5,668 MW in June 2016.

But MISO's Independent Market Monitor challenged the RTOs' assertion that pseudo-tied generation has operated reliably.

IMM staffer Michael Wander asked if either RTO could deny that they've experienced control room "emergencies" as a result of poorly managed pseudo-ties, but both Vannoy and PJM officials said they didn't understand the question and would not answer it.

"Let me rephrase. Would you say there haven't been any extraordinary actions taken?" Wander asked. "Because when you say you've implemented those reliably, that means business as usual, but that's not what I'm hearing from reliability coordinators."

MISO and PJM staff denied that pseudo-ties have affected reliability.

Wander ended the exchange by saying he would provide RTO leaders with confidential pseudo-tie data that have been troubling the Monitor. Staff agreed they could hold a later discussion on the matter.

MISO NEWS

MISO, SPP Look to Ease Interregional Project Criteria

By Amanda Durish Cook

MISO and SPP officials and staff meet at the IPSAC. | © RTO Insider

MISO and SPP are ready to reform their interregional planning process to improve their shot at producing their first cross-border transmission project, but they plan to wait a year before launching a joint study to identify such a project, the RTOs said last week.

At a Feb. 27 MISO-SPP Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting, the RTOs admitted that criteria spelled out in their joint operating agreement might be preventing beneficial interregional projects from gaining approval. They said they are ready to work with stakeholders through the summer to ease some restrictions.

SPP Interregional Coordinator Adam Bell said the RTOs' latest coordinated system plan study, concluded in 2017, showed they are still inconsistent in how they calculate adjusted production costs, develop regional models and review regional project proposals. Before being approved, proposed interregional projects must clear separate regional reviews by each RTO in addition to passing a joint review.

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

"We've learned a lot in both coordinated plans we've done," Bell said. "Both SPP and MISO are interested in doing meaningful planning between our systems, and we want stakeholders to have faith in the process and feel good entering these studies. … Both RTOs support … designing a new study process that has stakeholder confidence. We've done this twice. Let's fix this thing."

Davey Lopez, MISO adviser of planning coordination and strategy, said the RTOs plan to collect stakeholder suggestions and do more research before returning to the IPSAC in May with recommendations on how to improve their joint planning. The RTOs plan to work with stakeholders through September to prepare a FERC filing to alter their JOA by the end of the year.

Comprising planning staff from both RTOs, the Joint Planning Committee will vote later this year on whether to pursue another coordinated system plan.

Staff from both RTOs cautioned that they were unlikely to develop a 2018/19 study because planners are inclined to concentrate fully on process improvements, but stakeholders will be provided a non-binding IPSAC vote on where planners should concentrate their efforts.

$5 Million Obstacle

SPP and MISO said a major piece of the overhaul would be lowering the RTOs' $5 million cost threshold for interregional projects.

"Hopefully, we can remove some of these hurdles on the coordinated system plan," Lopez said.

In response to a question by Entergy's Yarrow Etheredge, MISO and SPP staff declined to identify any specific project they would have liked to see pass but for the RTOs' stringent criteria, although Lopez noted a few instances in which lowering the $5 million threshold would have improved a project's chances in the last coordinated system plan.

"We really finished one study and started another, so we didn't have time to implement these improvements we identified," Bell said, referring to the short gap between the 2014/15 and 2016/17 studies. At the time, MISO recommended awaiting a second coordinated study while the RTOs worked out differences between their planning processes, but MISO eventually abandoned the idea in favor of starting another study.

Bell said it's imperative for the RTOs to align their adjusted production costs and more accurately model each other's systems. He suggested removing MISO and SPP's joint modeling efforts altogether in favor of working on more identical regional models. Several stakeholders objected to that idea, claiming it could complicate cost allocation between the RTOs. Bell pointed out that MISO and SPP would still have a joint study under his plan, just not a joint model.

The RTOs are additionally contemplating allowing for adjustments in modeling cost allocation to determine if the benefits of a project are amplified.

SPP also continues to support cost allocation for sub-345-kV interregional projects with MISO, Bell said, a subject that MISO continues to discuss, according to Lopez. MISO has proposed cost allocation changes for its market efficiency projects, including a sub-345-kV cost allocation and elimination of a footprint-wide postage stamp rate. (See *MISO Recommends Cost-Sharing for Sub-345 kV Tx*.)

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MISO News

MISO, SPP Look to Ease Interregional Project Criteria

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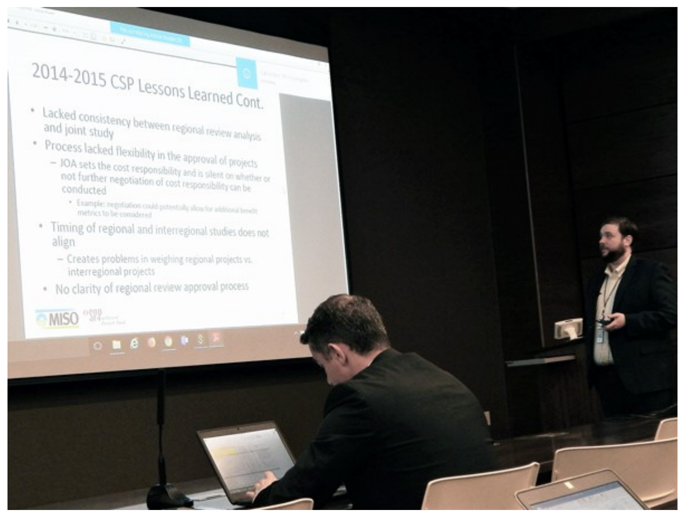
Entergy Critical of MISO-SPP TMEP

Entergy engineer Kyle Watson said the MISO-SPP seam does not yet have a structured enough coordination process to develop smaller interregional projects, such as those eligible to qualify under the new MISO-PJM targeted market efficiency project (TMEP) category, which relies on historical congestion to identify small transmission projects. MISO and PJM approved a $20 million, five-project TMEP portfolio late last year, representing the first interregional transmission projects between the two RTOs, and some stakeholders have called for a similar process on the MISO-SPP seam. (See *MISO Board Approves $2.6B Transmission Spending Package*.)

Entergy's Matt Brown said there isn't sufficient operational data since the integration of the company into MISO and the Western Area Power Administration into SPP to build a case for congestion-relieving projects. But SPP Director of Seams and Market Design David Kelley disagreed, saying MISO and SPP have already collected enough historical congestion data to justify projects that are less costly than continuing to pay market-to-market congestion charges.

"The day-ahead and real-time congestion is persisting," agreed Lopez.

During the IPSAC meeting, the RTOs pointed out that one congested flowgate on the Oklahoma-Kansas border has been responsible for nearly $20 million M2M payments since February 2017.



Adam Bell presents to the IPSAC. | © *RTO Insider*

Wind on the Wires' Natalie McIntire and WPPI Energy's Steve Leovy said their organizations are displeased that the RTOs are not inclined to begin another coordinated system plan this year, given that the 2016/17 plan focused narrowly on needs along SPP's Integrated System in North Dakota, South Dakota and Iowa, and the larger SPP-MISO seam has areas of congestion.

"There's a lot of consumers bearing costs because we're not fixing these issues," Leovy said. "There's need for a major interregional study."

"We're not happy, but we recognize there's general consensus beyond us," McIntire said.

NYISO NEWS

NY Task Force Takes on Carbon Pricing Mechanics

By Michael Kuser

How should New York set carbon prices — and who should be tasked with doing it?

Those were questions the state's Integrating Public Policy Task Force (IPPTF) began to tackle Feb. 26 in "Track 3" of the group's effort to integrate carbon pricing into NYISO's wholesale electricity market.

The group also touched on issues related to "Track 4," which covers the specific interactions of carbon pricing with other state and regional programs, such as the renewable energy credit (REC) and zero-emission credit (ZEC) programs, as well as the Regional Greenhouse Gas Initiative.

The effort to price carbon into the state's wholesale electricity market is a joint effort by NYISO and the state's Department of Public Service (17-01821).

On pricing, stakeholders at the IPPTF debated whether to use a nominal value of $1/ton or $40/ton in their calculations for a carbon charge — or whether the debate was a waste of time given that the state's Public Service Commission would ultimately decide the number.

Representing New York City, Couch White attorney Kevin Lang suggested participants examine different sources for a social cost of carbon, both international and national.

"If we're trying to get something that is valid through time, not just through two or three years, but over a longer time period, hopefully we can look at what the different sources are and come up with something that is a little bit more rational and perhaps a little more stable or less volatile than politically influenced numbers," Lang said.

Ben Carron, National Grid's senior analyst for regulatory strategy and integrated analytics, said the price should be based on the cost of abating emissions, as abatement is the goal of the public policy.

"Doing a locational analysis would also be appropriate because in order to get an abatement cost, obviously it will cost different amounts to build renewable generation than to abate carbon in different areas, like upstate," he said.

Carron said his company could envision "something like a renewable net [cost of new entry] with a renewable demand curve that sets the cost of carbon in a given area, which would not only provide a more efficient price, a locational cost of carbon abatement but also provide the price signal for transmission build that would be necessary to truly evaluate whether or not it was an efficient investment."

Marc Montalvo, of the DPS' Utility Intervention Unit, said it makes sense for stakeholders to "seed our thought process" with various sources related to social cost of carbon, but that the price would ultimately come down to "the minimum charge that achieves the [Clean Energy Standard] objectives ... and analytically we should be trying to determine what that number is."

New York City Deputy Director for Infrastructure Susanne DesRoches said, "Those goals and objectives from the CES need to be clearly defined as to what the carbon charge is trying to solve for. You can look at other models and look at what their goals are, what they were trying to solve for and how those structures supported that end goal, but without a clear understanding of what this effort is trying to solve for, I think it will be difficult to put a number on the cost of carbon."

Warren Myers, DPS chief of regulatory economics, said the PSC would be setting the price of carbon in another forum.

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NYISO News

Management Committee Briefs

MC Approves Day-Ahead Market Congestion Settlements

RENSSELAER, N.Y. — NYISO's Management Committee on Wednesday approved proposed rule revisions that would allocate day-ahead market congestion rent shortfalls and surpluses stemming from changes in transmission availability to the responsible transmission owner.

The measure, which would revise Attachment N of the ISO's Tariff, will go to the Board of Directors for approval before a filing with FERC. The Business Issues Committee (BIC) recommended the proposal to the MC. (See "Day-Ahead Market Congestion Settlements," NYISO Business Issues Committee Briefs: Feb. 14, 2018.)

At the Feb. 28 MC meeting, Operations Analysis and Services Supervisor Tolu Dina explained that the ISO's proposed cost allocation methodology employs a *de minimis* threshold to determine when TOs are not allocated costs. The threshold applies to day-ahead constraint residuals less than $5,000, provided the sum of all such residuals falling below the threshold is not more than $250,000 or 5% of the sum of all day-ahead constraint residuals for the month.

Alternative Methods for Determining LCRs

The MC approved Tariff revisions to establish an alternative method for calculating locational minimum installed capacity requirements.

The revisions incorporate incremental changes recommended by stakeholders at the Feb. 6 Installed Capacity Working Group/Market Issues Working Group meeting, said Zachary Stines, NYISO associate market design specialist. (See "Alternative Methods for Determining LCRs," NYISO Business Issues Committee Briefs: Feb. 14, 2018.)

Stines presented the new method for determining locational capacity requirements (LCRs) for localities, designed to minimize the total cost of capacity at the level of excess condition while meeting reliability criterion, maintain the installed reserve margin approved by the New York State Reliability Council and not exceed transmission security limits.

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

The Long Island Power Authority, NRG Energy and other stakeholders recommended sending the measure back to a working group for additional analysis. But other market participants countered that while a case can always be made for more analysis in a big project, the proposal — while imperfect — represents an improved approach for estimating requirements.

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NY Task Force Takes on Carbon Pricing Mechanics

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"So, debating abatement versus damage costs, I don't think is that relevant here [and is] only [relevant] to the extent that it influences the straw level of carbon pricing we use for our modeling efforts," Myers said, adding that the PSC is at least likely to "listen to our arguments about abatement costs."

REC, ZEC and RGGI

Speaking about how pricing carbon might interact with other state and regional programs such as REC, ZEC and RGGI, Long Island Power Authority Director of Wholesale Market Policy David Clarke, asked whether RGGI impacts would diminish the effect of carbon pricing in New York.

"We would need to reduce the RGGI targets to reflect the impact of the carbon pricing as well as CES ... otherwise, RGGI itself would see a lower price, absent a ratcheting down of the RGGI requirements," Clarke said.

"Other folks outside of New York would be able to emit more, taking back some or all of the requirements. This is one where you need to think through this and make sure we don't have the takebacks associated with not reflecting any carbon pricing in the RGGI requirements."

Representing a coalition of large industrial, commercial, and institutional energy customers, Couch White attorney Michael Mager said, "From a consumer perspective it's a clear windfall on double payments. Despite arguments by some parties, including us, the commission time and time again has gone ahead and forced customers to bear the brunt of 20-year fixed contracts, where we are paying for carbon-free emissions under contract."

One of the main purposes of the PSC moving to competitive electricity markets is to shift the risk of generation ownership from consumers to developers and owners, who willingly choose those risks, he said.

"There will be risks, there always will be, but lately, one by one, a lot of these risks are being shifted back onto consumers, despite the original intent," Mager said.

If the RGGI system shifts all New York's carbon reductions to the other RGGI states, "and there's essentially zero or hardly any carbon reduction from this, then whatever the price tag is, it's probably too high," Mager said.

Myers said one stakeholder concern is that "we add through policies, regulations, and government an externality price to the wholesale market ... if the development community doesn't know if they can trust this policy to hang around for more than a year or two, you could be kidding yourself on not paying twice even with future contracts."

IPPTF Co-Chair Nicole Bouchez, NYISO market design specialist, said the group would next meet to discuss Track 3 on April 16 and Track 4 on May 14, with the goal of delivering recommendations by October.

Bouchez also noted that there would be no IPPTF meeting March 5 but that the task force would next reconvene at NYISO headquarters on March 12.

NYISO NEWS

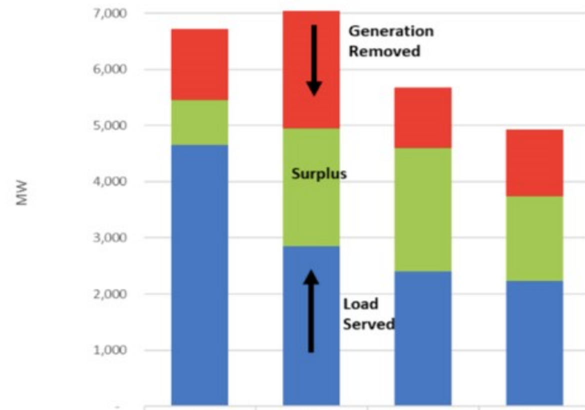
Management Committee Briefs

Continued from page 22

MC Rejects On Ramp/ Off Ramp Changes

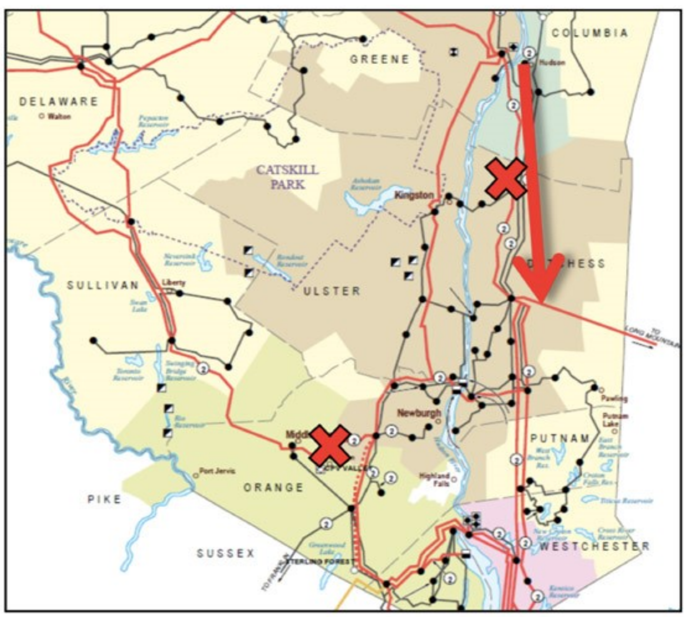
The MC rejected a market design proposal and related Tariff revisions that would have eliminated localities and revised the existing on ramp/off ramp rules to create a new locality.

The BIC rejected the same proposal on Feb. 14. (See "BIC Rejects On Ramp/Off Ramp Changes," NYISO Business Issues Committee Briefs: Feb. 14, 2018.)



	AB	C	F	G
Generation Removed for Create Test	1,264	2,085	1,076	1,190
Approx. Surplus	800	2,100	2,200	1,500
Load	4,653	2,852	2,401	2,238

On ramp/off ramp test | *NYISO*



G-J locality elimination test example | *NYISO*

Zach T. Smith, NYISO manager of capacity market design, told the MC the proposed methodology is based on reliability planning principles developed to determine whether to create and eliminate localities.

The unique geographic nature of Zones J and K, encompassing New York City and Long Island, makes it difficult to site generation in those areas, which also confront distinct environmental issues, Smith said.

Mark Younger of Hudson Energy Economics reiterated the objections he made at the BIC meeting earlier in the month, calling the market design proposal — and NYISO's review process — "flawed."

BIC Chair Erin Hogan said NYISO received about 10 letters of support for the capacity market design from members of the public, the first time she recalled such a response. The letters will be posted on the ISO's website.

— Michael Kuser

FERC Denies Rehearing on NextEra NYISO Adder

FERC last week rejected the New York Public Service Commission's request to rehear a November 2017 decision granting NextEra Energy Transmission New York (NEET NY) a 50-basis-point adder for participating in NYISO.

The ISO in October selected the company's Empire State Line proposal to address a need for new transmission in western New York.

FERC's Feb. 28 order dismissed the PSC's argument that a participation adder — or membership incentive — was unnecessary because NYISO selected NextEra as part of its transmission planning process, leaving the company no choice but to turn over operational control of its transmission to the ISO (ER16-2719).

The federal commission countered that the incentive recognizes the consumer benefits, including reliability and cost benefits, that flow from ISO membership.

Section 219 of the Federal Power Act provides for incentives to each transmitting utility or electric utility that joins an RTO/ISO, and incentive-based rate treatments benefit consumers by ensuring reliability and reducing the cost of delivered power, FERC said.

"We consider an inducement for utilities to join, and remain in, transmission organizations to be entirely consistent with those purposes ... and the best way to ensure those benefits are spread to as many consumers as possible is to provide an incentive that is widely available to member utilities ... and is effective for the entire duration of a utility's membership in the transmission organization," FERC said.

FERC granted NEET NY's request subject to the return on equity with the adder being within the zone of reasonableness, it noted.

— Michael Kuser

PJM NEWS

PJM Proposes One-Time Frequency Response Recovery

By Rory D. Sweeney

The Primary Frequency Response Senior Task Force met Feb. 28. | *© RTO Insider*

VALLEY FORGE, Pa. — PJM won't be offering market compensation to comply with FERC's requirement that almost all resources provide primary frequency response (PFR), but the RTO is willing to give everyone a shot at recovering any upgrade costs to provide it.

RTO staff unveiled their newest proposal on the issue at a meeting of the Primary Frequency Response Senior Task Force (PFRSTF) on Wednesday. The idea generated some stakeholder interest but also created plenty of concern in light of FERC's recent ruling. (See *FERC Finalizes Frequency Response Requirement*.)

"In general, we're going to disagree with all of this," said Carl Johnson, representing the PJM Public Power Coalition. "We are not in favor of where PJM is going with this."

Johnson said it would create a substantial cost to customers for something that should be baked into the cost of doing business. He said PJM would likely hear from the consumer advocates on the issue.

Staff said they couldn't quantify the overall cost but would get back to stakeholders with estimates.

Applicable units could seek the cost recovery or include it in their capacity offers, but they couldn't do both. Howard Haas of Monitoring Analytics, the Independent Market Monitor, outlined a situation in which units that sought the recovery could also clear the auction at a clearing price set by another unit's bid that includes the upgrade costs.

"From our position, that would be double recovery," he said.

The Monitor's proposal argues that units already have opportunities to recover the cost through capacity or energy offers.

"I've got good news for you," he said. "You're already being compensated."

CPower's Bruce Campbell said he would have to review how distributed energy resources are handled in his company's proposal.

PJM's proposal also increased its proposed threshold for exempting units, from 10 MW to 20 MW, because the potential benefit from such small units might not outweigh the upgrade costs.

Brock Ondayko with American Electric Power disagreed with Haas on whether units could seek recovery. AEP's proposal

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PJM, TOs Propose FERC Order 890 Compliance Plan

By Rory D. Sweeney

PJM and its transmission owners released a joint proposal last week to address FERC's decision last month that the TOs are not in compliance with Order 890 (EL16-71, ER17-179).

The commission ruled that the TOs were failing to provide stakeholders with adequate notification, information and enough opportunities to engage on "supplemental" projects — transmission expansions or enhancements not required for compliance with reliability, operational performance or economic criteria. The projects are part of PJM's Regional Transmission Expansion Plan but not subject to staff's oversight and approval. (See *FERC Orders New Rules for Supplemental Tx Projects in PJM*.)

FERC ordered the TOs to define nine time-period minimums that were previously vague. In response, TOs have proposed there be a minimum of 25 days between meetings on the three parts of project planning: assumptions, needs and solutions. They also offered to post information to be discussed at that meeting 10 days ahead of time and allow 10 days after meetings to receive comments. Finally, they proposed a 10-day waiting period to consider written comments before incorporating their local transmission plans into the RTEP.

"The minimum time periods proposed are designed to complete the consideration of supplemental projects in time for the PJM board meeting to approve the Regional Transmission Expansion Plan in July and in subsequent RTEP approval cycles throughout the year," PJM and the TOs wrote in the joint proposal.

PJM is giving stakeholders until March 9 to comment on the proposal. But some have already said they aren't yet ready to sign off.

"We are carefully reviewing the filing with a view of the current planning process as well as the language in the order," said American Municipal Power's Ed Tatum, who has been a vocal critic of the process. "Absent discussion with the TOs, PJM and other stakeholders, it is difficult to determine if the time frames and process proposed will yield any improvement to the current process."

PJM News

PJM Proposes One-Time Frequency Response Recovery

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would allow units to petition FERC for recovery if they feel they need it and can justify the request. Ondayko said he would consider PJM's one-time recovery proposal, but he also mentioned concerns about the cost to customers because provision of PFR isn't a NERC requirement.

PJM's Glen Boyle said PFR is a requirement for balancing authorities and therefore an "implicit" requirement for resources.

FirstEnergy's Jim Benchek agreed with other members that PJM's proposal seemed to be giving some BAs "a free pass."

"Is this a solution looking for a problem?" he asked.

AEP's proposal diverged from PJM's on how performance would be evaluated. Both agreed that the calculation should be a quarterly pass/fail test on whether units provided at least half of the PFR they were expected to provide. AEP suggested a higher deviation and longer duration of frequency outside the deadband settings before performance could be evaluated.

"There should be something there that makes it possible to identify the unit response from the noise," AEP's Jim Fletcher said.

PJM's Danielle Croop said staff would consider rolling that into their proposal.

"If we're going to put that minimum of five or six events in there … we want to make sure that we're still able to perform these evaluations on a quarterly basis and that it's not that we're sitting around waiting for events to happen," she said.

Staff noted that in the 2017 operating year, there would have been 14 events that fit AEP's standards, which wouldn't allow for the six events per quarter that PJM planned to use for evaluation. AEP proposed evaluating five events each quarter because they would be "more meaningful," Ondayko said.

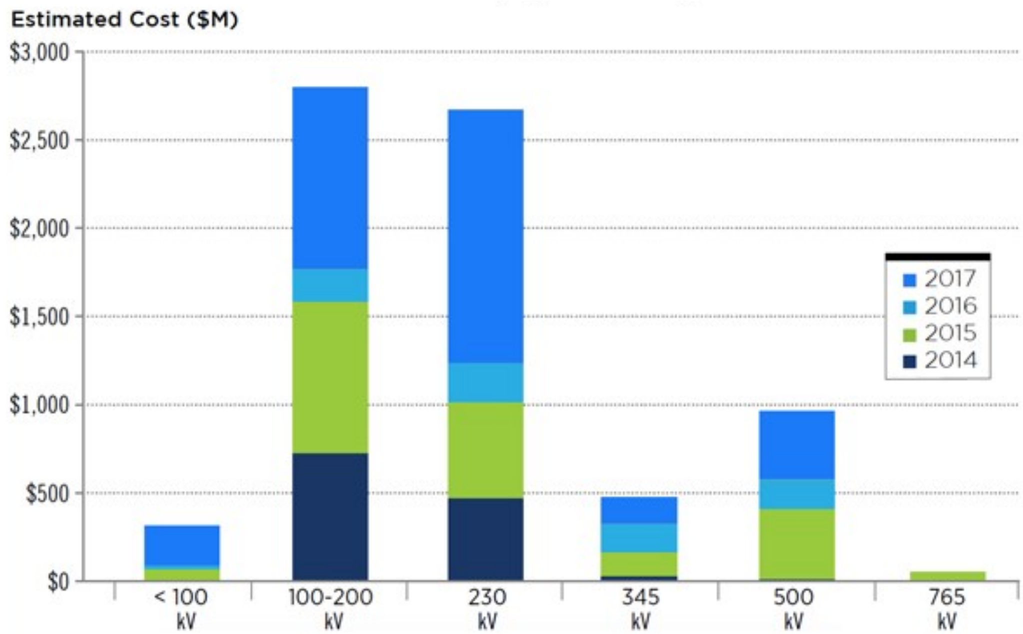
AEP also suggested researching the importance of synchronous inertial response and preserving "what we have today because once it's gone, it's gone for good," Fletcher said.

"If you look at interconnections that are losing their synchronous inertial response, like Texas, you'll find that they have to resort to paying load resources to compensate for the fact that there isn't enough primary frequency response anymore to cover that deficit, so the operation of the grid becomes more erratic … and the need for primary frequency response goes up, but there's limited capability," Ondayko said. "We recommend that this type of concept be considered in the future, at least recognizing the issue of how it impacts restoration."

PJM NEWS

PJM Report Highlights Struggle to Replace Infrastructure

By Rory D. Sweeney



Approved baseline projects by voltage, 2014-2017 | *PJM*

PJM is experiencing an "unprecedented" switch from coal- to gas-fired generation while also managing the replacement of aging transmission infrastructure, staff concluded in the RTO's annual transmission planning report.

The RTO received deactivation notices for 4,588 MW of generation in 2017, bringing the total since the end of 2011 to 34,967 MW. Deactivation requests in the eight years prior totaled 11,000 MW.

PJM greenlit $5.8 billion in transmission spending last year. That paid for 198 "baseline" projects to ensure compliance with NERC, regional and local transmission owner planning criteria, and 341 "network" projects to interconnect new generating stations. According to the RTO's figures, that comes out to about $16 million per baseline project and about $8.6 million per network project.

On Feb. 14, PJM's Board of Managers authorized another $397 million in transmission projects, dominated by TOs' supplemental projects that are triggered by their own planning criteria. Transmission customers have complained about the uptick in such projects, which don't require PJM board authorization but are included in the Regional Transmission Expansion Plan, because they believe TOs are using them to pad revenues. (See *AMP Presses AEP, PSE&G on Transmission Projects*.)

The recent approvals include two such efforts in the Public Service Electric and Gas and Dominion Energy territories. PSE&G plans to spend $115 million to construct a 230/69-kV substation with 69-kV ties to the Paramus and Dumont substations, and $98 million to convert the Kuller Road substation to 69/13 kV and construct a 69-kV network between the Kuller Road, Passaic, Paterson and Harvey stations. Dominion will replace existing infrastructure for a total of $50 million.

The remainder of the approvals consist of another Dominion project — $100 million to install three STATCOM dynamic reactive devices at two substations — and $29.5 million in spending spread across projects in the Baltimore Electric and Gas, PPL and Duke Energy Ohio/Kentucky territories.

Last month, FERC ordered PJM's TOs to change their process for handling supplemental projects after finding the current approach does not comply with Order 890. TOs worked with PJM on the issue and last week proposed a plan to address the commission's concerns. (See related story, *PJM, TOs Propose FERC Order 890 Compliance Plan*, p.24.)

The PJM board has authorized $35.4 billion in transmission infrastructure spending since 1999. Baseline projects represent $27.9 billion of the total, with $7.2 billion authorized to interconnect 84,200 MW generation. Those figures include $181 million in cost overruns for 48 previously approved baseline projects and $540 million authorized for 336 network projects that were canceled after 257 generator interconnection requests were withdrawn, which reduced expenditures below authorized levels.

But the numbers also provide some insight into development trends. PJM said the 2017 projects address market efficiency congestion and solve local reliability issues, and recent history shows a trend toward smaller lines rather than large, backbone-sized construction.

"Flat load growth, energy efficiency, generation shifts and aging infrastructure drivers — among others — continue to shift transmission need away from large-scale, cross-system backbone projects at 345 kV, 500 kV and 765 kV voltage levels," the report states.

The generation interconnection queue is dominated by gas-fired facilities, and the deactivation list is littered with coal plants, but the fleet won't be changing too much any time soon. PJM estimates that oil, wind, hydro and solar will all look about the same five years from now in 2023: slightly more than 10% of the total generation fleet.

Nuclear will drop slightly from somewhat less than 20% today to about 18% in 2023. Coal will also be down from around 31% today to about 28%. Gas increases significantly from roughly 40% today to more than 45%. PJM has said it can remain reliable with upward of 86% gas. (See *PJM: Increased Gas Won't Hurt Reliability, Too Much Solar Will*.)

SPP NEWS

Oklahoma Regulator Sets Sights on Higher Office

By Tom Kleckner

LITTLE ROCK, Ark. — As the chair of SPP's Regional State Committee in 2015, Oklahoma Corporation Commission (OCC) Chair Dana Murphy would, without fail, compliment her fellow committee members, regulatory and SPP staff, and other stakeholders for their efforts, no matter how small.

But that's just Dana Murphy.

"I feel very grateful," she said about her practice of recognizing others. "The thing is, there's always going to be a healthy tension between regulators and SPP and the utilities, and I accept that. I accept that as part of the job, whether I'm serving as a commissioner in Oklahoma or representing Oklahoma here on the RSC.

"I don't try to avoid [the tension]. The challenge with all of this — and it may be hard to believe — is that I'm an introvert who doesn't like controversy. Yet, how did I get here?"

After serving on the OCC since 2008, and as its chair since February 2017, Murphy has set her sights on the lieutenant governor's office.

She opened her campaign last July with a prayer in her hometown of Edmond. "I think all of you who know me know that my faith is the biggest part of pretty much everything I do beyond my family," Murphy said.

Murphy speaks with SPP Director Harry Skilton at a July RSC meeting in Denver. | © *RTO Insider*

Field of Four

Murphy is competing with three other Republicans — state Sen. Eddie Fields, former state party chair Matt Pinnell and "entrepreneurship consultant" Dominique DaMon Block Sr. — for the GOP's slot in November's statewide elections. The primary is June 26.

The commissioner has claimed a significant fundraising edge over her three primary opponents, finishing 2017 with $690,000 on hand after shifting nearly $639,000 from her OCC campaign account. Pinnell had $450,000 on hand, but outraised Murphy in the fourth quarter, $113,000 to her $44,000. Fields finished the year with $65,274 in funds; Block had nothing. Murphy's donors include oil and gas executives, attorneys, insurance executives, lobbyists, real estate developers, bankers and real estate developers.

Murphy's campaign website pledges "to address the roots of the longstanding problems facing our state, including the budget, education, health care and infrastructure," but it is light on policy details.

Instead she highlights her Oklahoma roots and writes of putting more than 180,000 miles on her "little blue truck" to attend events statewide and "visit folks just like you."

A fifth-generation Oklahoman, Murphy grew up on a ranch, graduated from Oklahoma State University with honors and first worked as a petroleum geologist. As Murphy says on her website, her family encouraged her to "do more and be more," so she earned a night school law degree from Oklahoma City University while working as a law clerk.

The state's Sooner Poll has yet to release results of the lieutenant governor's race, but Pinnell appears to be her strongest opponent. Besides his fundraising prowess, he has built inroads with the national Republican Party by working as a campaign manager for the GOP in all 50 states.

Former Missouri Public Service Commissioner Steve Stoll, who served alongside Murphy on the RSC before cycling off the committee and his state's commission in January, recalled her as "a very hard worker."

"I know she cared deeply about the state and wanted to ensure her ratepayers were treated fairly," he said.

"She has deep knowledge of the energy business, and energy is an integral component to the Oklahoma economy," said SPP General Counsel Paul Suskie, who works closely with the RSC.

After six years as an administrative law judge for the OCC, Murphy won a seat on the commission in a 2008 special election. She was re-elected to full terms in 2010 and 2016 and has seen her workload grow from normal petroleum and electricity issues to ride-sharing companies and seismic activity related to fracking.

"To make really difficult decisions is something I've spent nine years on," she said, referring to reaching consensus with the OCC's other two commissioners, Vice Chair Todd Hiett and Bob Anthony. "We don't have the same opinions on a lot of things, yet somehow, we have to find a way to work together to make decisions. You look at the stakeholders that we deal with, with very divergent opinions and decisions … you have to have the ability to try and process all that and make some really difficult decisions that ultimately, everyone is going to be unhappy with."

Doing More with Less

Complicating matters, Murphy says, is that the OCC has been asked "to do more with less."

Continued on page 28

SPP NEWS

Oklahoma Regulator Sets Sights on Higher Office

Continued from page 27

"Our appropriations from the legislature continue to go down, but our authority and responsibility by statute have increased, just in the nine years I've been there," she said.

Some Oklahoma utilities and petroleum companies have complained about the OCC's delay in resolving rate cases, which has resulted in interim rates being implemented, subject to refund. Oklahoma law allows the commission to implement interim rates if the cases aren't resolved in 180 days.

OGE Energy has led the complaints against the process, which reached a crescendo when its December 2015 request for $92.5 million was implemented on an interim basis of $69.5 million in the summer of 2016. The OCC gave OGE's Oklahoma Gas & Electric utility customers a $47.5 million refund when the rate case eventually concluded last April.

"We are investing north of $500 million in our system every year. I think it's my job to be supportive of the state, but we've got to be able to come up with a way to recover that in a timely manner," OGE CEO Sean Trauschke said last month during the company's most recent earnings call with analysts.

Oklahoma Gov. Mary Fallin (R) has responded to the outcry by forming a task force to suggest ways to improve the commission's performance. (See *OGE Anticipates Legislative Review of Oklahoma Regulators*.) For her part, Murphy says she is hopeful the task force will increase awareness of the OCC's challenges and responsibilities.

Lieutenant governor may not be Murphy's ultimate goal. Oklahoma media note the position is seen as a stepping stone to the governor's mansion. Case in point: Lt. Gov.

Murphy speaks at the RSC as SPP CEO Nick Brown (left) and New Mexico PRC Commissioner Pat Lyons listen. | © *RTO Insider*

Todd Lamb, an early frontrunner for this year's GOP's gubernatorial nomination, is now running second to Oklahoma City Mayor Mick Cornett in a crowded field. They are battling to replace the term-limited Fallin, who was elected governor in 2010 after previously serving as lieutenant governor and a U.S. representative.

Murphy, whose term ends in 2022, said she will continue to represent the OCC on the RSC and serve at the commission during her campaign for higher office. As she put it, "I'm here until I'm not here."

FERC & Federal News

Coalition Targets Capacity Markets in Resiliency Docket

By Rich Heidorn Jr.

A coalition of consumer advocates, environmentalists, wind and solar developers and public power laid down a marker in FERC's resilience docket Tuesday, calling on the commission to "review the design of organized wholesale electricity markets, particularly capacity constructs."

The group — the American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association and the Transmission Access Policy Study Group from public power; the Electricity Consumers Resource Council (ELCON) and National Association of State Utility Consumer Advocates, representing load; and green energy proponents Natural Resources Defense Council, American Council on Renewable Energy, American Wind Energy Association and Solar Energy Industries Association — sent a letter to the commission listing five "principles" it said FERC should embrace in future rulings.

The group said the letter would be filed in the dockets on the intersection of markets and state policies (AD17-11) and on grid resilience (AD18-7). RTOs have a Friday deadline to file their responses to the commission's questions in the resilience docket, which the commission opened when it dismissed Energy Secretary Rick Perry's call for price supports for coal and nuclear generators. (See *FERC Rejects DOE Rule, Opens RTO 'Resilience' Inquiry*.)

The principles: technology-neutral market rules; wholesale market rules that respect state and local resource choices and don't make customers pay twice; allowing self-supply without RTO "second guessing"; no guaranteed recovery of investment costs for particular resources or technologies; and allowing markets "to function and stabilize before new solutions are deemed necessary to be implemented."

"The capacity constructs include design features that may limit choice, create conflicts with state and local policy objectives, over-procure or unnecessarily retain capacity, and raise costs for customers," the letter says, calling for avoiding "costly over-procurement."

"We as a group are committed to contributing to solutions," the letter continued. "We emphasize that solving this challenge directly and holistically, rather than layering costly Band-Aids on top of organized wholesale markets, will benefit customers most in the long run."

FERC may ultimately rule that the coalition's effort to inject a review of the capacity markets in PJM, ISO-NE and NYISO is out of the scope it set in the resiliency docket. The commission directed all RTOs and ISOs to identify their resilience risks; whether they should assess their resource portfolios against contingencies from the loss of key infrastructure; and the bulk power system attributes that contribute to resilience.

The issue is more central in docket AD17-11, the subject of a two-day FERC technical conference in May. (See *Power Markets at Risk from State Actions, Speakers Tell FERC*.)

But the breadth of the coalition indicates that disenchantment with mandatory capacity markets — which public power has questioned since their inception — has grown as state officials attempt to execute climate policies in the face of markets that ignore carbon emissions.

The group's letter, however, noted the limits of the alliance, saying, "These design principles work together; individual signatories do not necessarily support every principle if other principles are not also honored."

FERC & FEDERAL NEWS

APPA Celebrates Recent Victories; Presses on Infrastructure

By Rich Heidorn Jr.

APPA spokesman Tobias Seller readies the conference speakers to begin the press conference as Delia Patterson, Sue Kelly and Desmarie Waterhouse await. | *© RTO Insider*

WASHINGTON — American Public Power Association CEO Sue Kelly has been railing for years against RTO capacity market and stakeholder rules she says are skewed in favor of large transmission and generation owners.

Sue Kelly | *© RTO Insider*

Last week, as 600 APPA members gathered at the historic Mayflower Hotel for their annual Legislative Rally, the group could celebrate recent policy victories on both fronts.

On Feb. 23, FERC ordered a technical conference to consider whether PJM should move from a year-round to a seasonal capacity construct, indicating that the newly constituted commission is having second thoughts about the restrictive Capacity Performance rules FERC approved in 2015. (See *FERC Rethinking PJM Capacity Performance Rules*.) APPA had opposed CP as an overreaction to the 2014 polar vortex, saying PJM and market participants had largely addressed reliability problems through other measures.

FERC also backed public power's position in a Feb. 15 ruling that PJM transmission owners' processes for developing supplemental projects violate Order 890's transparency and coordination requirements. (See *FERC Orders New Rules for Supplemental Tx Projects in PJM*.)

In California, meanwhile, proponents of legislation that could enable CAISO's growth into a Western RTO said the grid operator would not back mandatory capacity markets. (See *Calif. Lawmakers Relaunch CAISO Regionalization*.)

Kelly said that although APPA doesn't lobby state government, it is pleased with the promise.

"Obviously, the California municipal utilities are an active and involved bunch," Kelly said. "I will say that our members in the West have witnessed what went on in the East. It's the old 'Fool me once, shame on you. Fool me twice, shame on us.'"

A resolution approved by APPA's Legislative & Resolutions Committee earlier Feb. 27 called for "consumer benefits and participatory multistate governance" as essential elements of a Western RTO.

The committee also approved resolutions on supplemental transmission, electric vehicles, disaster response, infrastructure investments and the Public Utility Regulatory Policies Act of 1978.

After the votes, many of the attendees — including public utility executives, mayors and council members for cities with municipal utilities — went off to the Capitol to lobby Congress on their concerns.

Fighting Privatization

It hasn't all gone APPA's way of late, of course. The group is fighting a rear-guard action to block President Trump's proposal to divest the transmission assets of the Tennessee Valley Authority, Southwestern Power Administration, Western Area Power Administration and Bonneville Power Administration.

"We believe that the public power business model is a very strong one," Kelly said.

APPA also is backing bipartisan legislation introduced in February to restore the ability of public power utilities to advance refund private activity bonds — a way of prepaying higher cost debt (H.R. 5003). "While we were largely successful in the tax bill that just passed at the end of 2017 in protecting and maintaining municipal bond financing — for which we are most grateful to Congress, don't get us wrong — our ability to advance refund was taken away as part of that legislation," Kelly said.

APPA leaders also were to meet with all five FERC commissioners this week to press their longstanding concerns about RTO wholesale markets.

"We are quite concerned about wholesale market rules that would make wholesale prices more volatile and impede our ability to self-supply," Kelly said. "And we would like to see RTOs stop overriding state and local decision-making."

State and local control also was the focus of APPA's resolution on distributed energy resources. "What works in Arizona may not work in New Hampshire. So, we believe Congress should not seek to federalize rate design or tip the scale [in favor] of any particular resource over others," Kelly said. "Allow those decisions to be made at the state and local level."

APPA filed comments Feb. 26 supporting EPA's Advanced Notice of Proposed Rulemaking on replacing the Clean Power Plan. It agrees that the Obama administration's final rule went beyond its authority under the Clean Air Act.

"We don't want [there to be] no regulation, but we want regulations that comport with what's allowed in Section 111, and that would be things within the fence line — not this fuel switching from coal to natural gas, natural gas to renewables," said Desmarie Waterhouse, vice president of government relations.

NRG Announces $1 Billion Share Buyback, $70 Million Sale

By Peter Key

NRG Energy said Thursday that its board has authorized the company to spend $1 billion to repurchase its own shares.

The company also said it has agreed to sell its Boston Energy Trading and Marketing subsidiary to Mitsubishi's Diamond Generating unit for $70 million.

The moves are the latest in a series of steps NRG has taken to boost its share price in response to pressure from Elliott Management, a hedge fund run by billionaire Paul Singer, and Bluescape Energy Partners, a private investment firm, which announced in January 2017 that they had taken a 9.4% stake in the company.

NRG last July announced a transformation plan that it said would improve its recurring costs and margins by $1.1 billion; raise from $2.5 billion to $4 billion in cash through asset sales; and remove $13 billion in debt from its balance sheet. The company took major steps to execute that plan last month when it agreed to sell its renewables business, its stake in NRG Yield and its South Central Generating subsidiary in transactions that will bring it $2.8 billion in cash and take $7 billion in debt off its books.

The company also said last month that it expects to announce more sales this year and has revised its total asset sales cash proceeds target under the transformation plan to $3.2 billion. (See *NRG Selling Renewables, Other Assets for $2.8 Billion*.) With the announcement of the Boston Energy sale, the company has reported sales totaling more than $3 billion, all of which are on track to close by the end of the year, CEO Mauricio Gutierrez said during the company's earnings call Thursday. As the closings progress and NRG completes the initial $500 million portion of its share repurchase program, it will look to kick off the second $500 million round of buybacks, he said.

Gutierrez also said NRG's GenOn Energy subsidiary, which is operating under bankruptcy protection, could transition to becoming a standalone company as early as September. GenOn's reorganization plan was approved by the U.S. Bankruptcy Court in Delaware in December, and its financial results are no longer included in NRG's. On Feb. 27, Platinum Equity said it has agreed to buy an 810-MW combined cycle gas-fired plant in Gettysburg, Pa., from GenOn for $520 million.

NRG posted a loss of $1.67 billion from continuing operations on revenue of $2.46 billion in the fourth quarter of 2017, compared to a loss of $891 million on revenue of $2.48 billion in the same quarter of 2016.

Company Briefs

Judge Denies SCE&G Motion to Dismiss Summer-Related Lawsuits

Circuit Court Judge John Hayes III issued an order March 2 denying South Carolina Electric & Gas' motion to dismiss five lawsuits alleging wrongful acts by the SCANA subsidiary in its failed attempt to expand the V.C. Summer nuclear power plant.

The class action lawsuits were filed after the July 31 decision by SCANA and Santee Cooper to pull the plug on the expansion. A South Carolina law had allowed SCE&G to increase rates nine times to cover the cost of the two reactors it and Santee Cooper were trying to add to the power plant.

An attorney for SCE&G had argued that the South Carolina Public Service Commission, not the court, should determine whether its customers should get money back.

More: *The State*

PECO CEO Adams Retiring, To be Replaced by Innocenzo

Craig Adams will retire as PECO Energy president and CEO effective March 30, the Exelon subsidiary said March 1.

Chief Financial Officer Mike Innocenzo will replace Adams. He also will assume Adams' role as Exelon executive vice president.


Adams

During a career that spanned more than 30 years, Adams served in various leadership roles at PECO and Exelon, including senior vice president and chief operating officer of PECO; chief supply officer for Exelon Business Services; and senior vice president for operations support for PECO and its sister utility, Commonwealth Edison. Adams began his energy industry career with Public Service Electric and Gas.

More: *PECO*

PSEG, Exelon Canceling Salem Projects, Cite Lack of Nuclear Subs

Public Service Enterprise Group said in a Feb. 28 Securities and Exchange Commission filing that it and Exelon have agreed "to cancel the funding of future capital projects at the Salem generating station that are not required to meet Nuclear Regulatory Commission or other regulatory requirements or that are not required to ensure its safe operation" because of the New Jersey Legislature's failure to pass a bill subsidizing the state's nuclear power plants.

PSEG and Exelon, which co-own the Salem County, N.J., plant, said "the funding of these projects may be restored when and if legislation is enacted in New Jersey that sufficiently values the attributes of nuclear generation and Salem benefits from such legislation."

PSEG said that "similar actions may be appropriate at its wholly owned Hope Creek generating station in New Jersey as well."

More: *Public Service Enterprise Group*

Docs Show Southern Knew Kemper Plans were over Budget

Southern Co. knew its attempt to have its power plant in Kemper County, Miss., use coal gasification technology would cost far more than the limit imposed by state regulators five years before it decided to make the power plant just burn natural gas, according to documents obtained and interviews conducted by *The Guardian*.

The documents show that, with the coal gasification technology, the plant would have required vastly more downtime for maintenance than originally predicted, with a 2014 report saying it would be offline 45% of its first five years rather than the 25% the

Continued on page 32

FERC Greenlights Great Plains-Westar Merger

By Amanda Durish Cook

FERC on Wednesday approved the proposed $14 billion merger between Great Plains Energy and Westar Energy, ruling that it would not have an adverse impact on market competition or rates in SPP.

The deal is still subject to approval by Kansas and Missouri regulators.

Missouri-based Great Plains owns Kansas City Power & Light, and Kansas-based Westar owns Kansas Gas and Electric. Kansas regulators last year pushed back on Great Plains' original plan to buy out Westar, spurring the companies to recast the transaction as a "merger of equals."

Under a revised plan filed with the Kansas Corporation Commission in late August, Great Plains proposed that the two companies would combine under a $14 billion holding company operating in both Kansas and Missouri. Westar shareholders would own about 52.5% of the company with Great Plains shareholders holding the rest, according to the amended merger application (18-KCPE-095-MER). The companies have pledged that the holding company will maintain separate debt and capital structures for each subsidiary. (See *Great Plains, Westar File Revised Merger Plan*.)

The deal would entail no cash exchange or transaction debt, and retail customers would receive $50 million in upfront bill credits across all rate jurisdictions. The combined company would serve about 1 million customers in Kansas and almost 600,000 customers in Missouri.

In approving the deal, FERC made clear that a five-year hold-harmless commitment agreed to by the two companies would not cover any costs related to Great Plains' failed bid to buy out Westar (EC17-171). Under that commitment, Great Plains and Westar have agreed not to seek to recover any costs related to integrating the companies unless they can demonstrate, through a Section 205 filing, that a merger activity yielded savings in excess of costs incurred.

But the commission clarified that because Great Plains' original acquisition strategy was "pursued but never completed," costs related to the transaction "should not be included as part of the hold-harmless commitment and cannot be recovered from ratepayers pursuant to it. The costs related to the 2016 transaction are instead subject to the commission's ordinary ratemaking principles under [Federal Power Act] Sections 205 and 206."

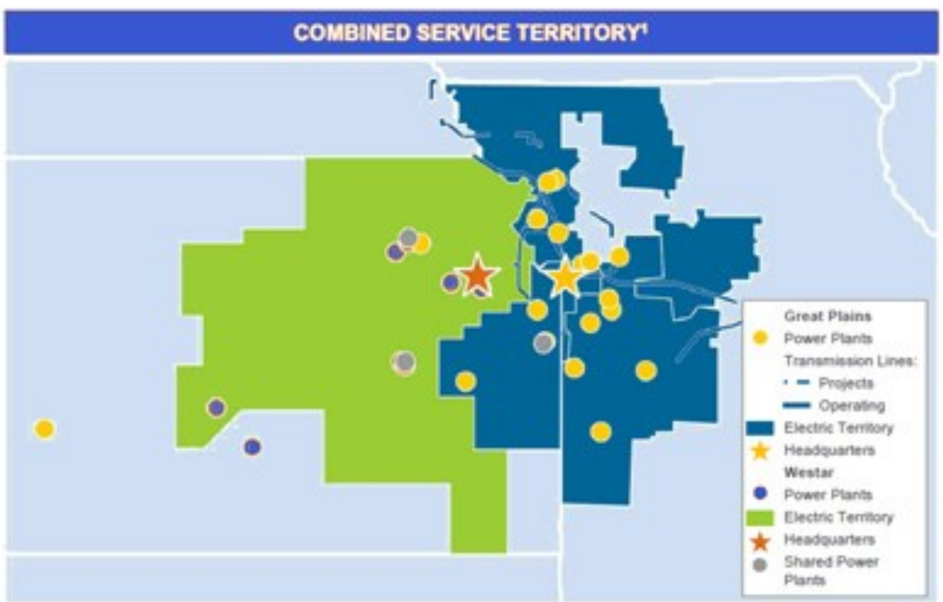
Additionally, FERC said it was not persuaded by a protest by Kansas Electric Power Cooperative, which asked the commission to apply an equally strong hold-harmless commitment to wholesale customers as it would for retail customers, using pre-merger common equity levels to calculate rates, shielding the co-op from merger-based rate impacts. It also asked that all hold-harmless commitments be indefinite.

FERC said ordering extra hold-harmless protections without evidence would be "speculative" and noted that it doesn't require merger plans to include hold-harmless commitments for market-based wholesale power sales.

The commission also declined the co-op's request that Great Plains and Westar provide it with a detailed list of all merger-related costs through a new compliance filing.

The proposed merger is still in prehearing stages at the KCC until March 19, when the first evidentiary hearing is scheduled. A public comment period on the merger ends March 29.

The Missouri Public Service Commission is also reviewing the proposed merger and will hold evidentiary hearings March 12 to 16 (EM-2018-0012).



| *Great Plains Energy, Westar Energy*

COMPANY BRIEFS

Continued from page 31

company had publicly projected.

Southern knew that three years before it decided to make Kemper just a natural gas plant, but it continued construction, sinking $3 billion more into the project.

More: *The Guardian*

Great Plains Signs PPA For 444 MW of Wind Power

Great Plains Energy said Feb. 26 it has signed two power purchase agreements for 444 MW of wind power from two facilities being built in Kansas.

One of the wind farms is the 244-MW Pratt Wind Energy Center in Pratt County. Owned by a subsidiary of NextEra Energy Resources, it is expected to be completed by the end of the year.

The other wind farm is the 200-MW Prairie Queen Wind Farm, which is owned by EDP Renewables. It's expected to be done by May 31, 2019.

More: *Kansas City Power & Light*

FEDERAL BRIEFS

Utilities Continue Cleanup Following Nor'easter

Utilities in New England and the Mid-Atlantic continued to work Monday to restore power to thousands of customers socked by the weekend's Nor'easter.

FirstEnergy said its Metropolitan Edison unit had restored service to more than 186,000 customers, with 35,000 customers still out of service as of Monday. Eastern Pennsylvania, including Stroudsburg and Easton, were hit by 50-mph winds and more than a foot of heavy, wet snow.

FirstEnergy's Jersey Central Power & Light had restored power to more than 131,000 customers, with 68,000 customers still out of service in New Jersey.

Dominion Energy had restored nearly 80% of the more than 690,000 customers that lost service by Monday. "This storm was particularly damaging as it lasted so long — with our system experiencing significant winds more than 24 hours including gusts of over 70 mph. It ranks as one of the top five most damaging storms in the number of Dominion Energy customers impacted, topped only by hurricanes Floyd, Isabel and Irene, and the Super Derecho of 2012," the company said.

Northern Virginia and the Gloucester/Northern Neck area in Virginia suffered heavy tree, pole and wire damage. Crews were slowed by having to take shelter during wind gusts.

Eversource Energy said it expects to restore service to all customers, including those on Cape Cod and Martha's Vineyard, which sustained the most significant damage from the storm, by the end of Tuesday.

National Grid said Monday afternoon that power had been restored to 88% of the more than 241,000 customers impacted by the storm.

EPA Proposes Giving more Latitude in Dealing with Coal Ash

EPA on March 1 proposed major changes to an Obama-era initiative regulating coal ash that would give states and utilities more latitude in deciding how to dispose of the waste product that results from burning coal to generate power.

The proposal includes more than a dozen suggested changes for the procedures used to store coal ash at power plants. It would extend the time that companies can maintain unlined coal ash ponds and let states change how frequently they test for groundwater contamination.

EPA Administrator Scott Pruitt said the changes, which could save power generators \$32 million to \$100 million a year in compliance costs, underscore the administration's commitment to federalism.

More: *The Washington Post*

Power Restoration Contract on Puerto Rico Expanded to \$945M

Cobra Acquisition's contract with the Puerto Rico Electric Power Authority and federal officials to restore the Puerto Rican grid has been increased to \$945 million. The subsidiary of Mammoth Energy Services has 922 workers on the island.

Cobra was awarded a \$200 million contract in October and sent 434 workers to Puerto Rico. In late January, the contract was expanded to \$500 million to cover a year's worth of work. By then, Cobra had 880 employees on the island.

More: *The Oklahoman*

NRC Rules Fuel Repository Proposal Can Move to Technical Review

The Nuclear Regulatory Commission ruled March 1 that Holtec International's proposal to temporarily store spent nuclear fuel in southern New Mexico is complete enough to begin the technical review process for it.

The company is seeking a 40-year license for an underground storage facility for the radioactive used fuel currently being stored on the grounds of the country's nuclear power plants.

The technical review process will feature expert testimony and public comment. Activists who think moving the fuel to the site carries a substantial risk are urging people to speak up about the proposal.

More: *The Associated Press*

DOE Program Review Created Uncertainty for Funding Recipients

A financial assistance review that the Department of Energy conducted of its Advanced Research Projects Agency-Energy program created significant uncertainty for recipients of its funding, according to the Government Accountability Office.

GAO said in a report issued Feb. 28 that 10 ARPA-E funding recipients told it that the uncertainty potentially delayed projects and created difficulty staffing project teams.

"Selectees told us that they received little communication from ARPA-E during the review process, and they indicated that additional information about review timelines and potential effects on their awards would have helped them manage some of the uncertainty they experienced during the review process," GAO said in the report.

More: *The Hill*

NRC Panel Discusses Restarting Yucca Mountain Licensing Process

The Nuclear Regulatory Commission's Licensing Support Network Advisory Review Panel held a hearing on Feb. 26 to receive input on rebuilding an electronic library for documents needed to rule on the Department of Energy's application for a license to build a repository for waste from nuclear power plants.

The meeting, which was the first in almost 15 years for the panel, is a preliminary step in the process of determining whether a nuclear waste repository should be built at Yucca Mountain in Nevada.

Representatives of rural Nevada counties, which support building the repository, took part in the hearing via the internet. The state of Nevada is opposed to building the repository and has been fighting it for years.

More: *Las Vegas Review-Journal*

FERC Finds No Evidence of Gas Pipeline Capacity Withholding

FERC said Feb. 27 that a staff inquiry has found no evidence of anticompetitive withholding of natural gas pipeline capacity by New England shippers on the Algonquin Gas Transmission system.

The commission undertook the inquiry after the Environmental Defense Fund alleged in an August 2017 white paper that local gas distribution companies in New England had engaged in practices to withhold pipeline capacity on the Algonquin system in order to drive up gas and/or power prices.

FERC said its staff determined that EDF's study was flawed and led to incorrect conclusions.

More: *FERC*

STATE BRIEFS

CALIFORNIA

PI Firm Hired by IID for Internal Review also Researched Critic

The Baker Street Group, a private investigations firm that the Imperial Irrigation District hired with ratepayer funds to help with an internal review of potential conflicts of interest, also conducted what IID's general manager called "opposition research" into a rooftop solar company run by a critic of the utility.

IID hired Baker Street to help with the review of potential conflicts of interests after *The Desert Sun* reported that the utility had spent millions on energy projects that benefited a former board member. But Baker Street also investigated Renova Energy, whose CEO, Vincent Battaglia, has bought radio and television ads criticizing IID.

IID General Manager Kevin Kelley defended the use of ratepayer dollars to scrutinize Renova, saying Battaglia "wasn't just a critic — he was communicating directly with our counsel and making fairly outrageous claims and allegations." Kelley also said Baker Street's work for IID was "larger than opposition research into the Renova fellow."

More: The Desert Sun

ILLINOIS

Commerce Commission Approves ComEd Microgrid

The Commerce Commission on Feb. 28 issued an order approving Commonwealth Edison's proposal to spend $25 million to build a microgrid in Chicago's Bronzeville neighborhood and be reimbursed by ratepayers for the project.

The project has been controversial, with opponents, including the state attorney general, saying it costs too much and that all ComEd ratepayers shouldn't be required to pay for something that will serve only 1,000 of them.

Its supporters, which include the Citizens Utility Board and Environmental Defense Fund, say it's an important experiment, and applaud a provision in the commission's order that could allow third parties to create their own microgrids in conjunction with ComEd.

More: Midwest Energy News

MISSOURI

Appeals Judge Transfers Grain Belt Express Case to Supreme Court

A judge in the Eastern District of the Court of Appeals on Feb. 27 ordered the Grain Belt Express' permitting case transferred to the Supreme Court.

Judge Lisa Page concluded that the Public Service Commission "erred" in finding that it couldn't authorize the transmission project because not all the counties that the project will run through had consented to it.

More: St. Louis Post-Dispatch

NEW JERSEY

Murphy Asks RGGI To Readmit State

Gov. Phil Murphy on Feb. 26 asked the member states of the Regional Greenhouse Gas Initiative to readmit the state to the cap-and-trade program, which is designed to reduce carbon emissions from power plants.

The state had been a RGGI member, but former Gov. Chris Christie withdrew it in 2011. Murphy said in his campaign he would seek to have the state rejoin the program, as did his Republican rival, Kim Guadagno, who was Christie's lieutenant governor.

Murphy signed an executive order last month to have the state rejoin the initiative, but member states must approve its re-entry. RGGI Chairman Ben Grumbles, secretary of Maryland's Department of the Environment, congratulated New Jersey on taking steps toward "renewed participation."

More: The Associated Press

BPU Implements Offshore Wind Economic Development Act

The Board of Public Utilities said Feb. 28 it has approved an order implementing the Offshore Wind Economic Development Act, moving the state toward a solicitation of 1,100 MW of offshore wind capacity.

In the order, the BPU directs its staff to establish an interagency Offshore Wind Task Force with the Department of Environmental Protection and other agencies to develop a strategic plan; begin the rulemaking process for establishing the funding mechanism for offshore wind renewable energy certificates (ORECs); and to prepare for the solicitation of the initial 1,100 MW of offshore wind capacity.

More: New Jersey Board of Public Utilities

NEW YORK

FERC OKs Incentives for NextEra Empire State Tx Project

FERC on Monday approved NextEra Energy Transmission New York's request for incentives for its Empire State Line Project, a 20-mile, 345-kV line through Niagara and Erie counties.

The commission approved NextEra's request for a 50-basis-point return on equity adder for risks and challenges in developing the project and a 50-basis-point adder as an independent transmission company, subject to the resulting ROE being within the zone of reasonableness the commission established in docket ER16-2719. It also granted the company 100% recovery of prudently incurred costs in the event the project is abandoned for reasons outside of the company's control and inclusion of 100% of construction work in progress in its rate base.

NYISO selected the Empire project as the most cost-effective solution to address the Western New York public policy need by providing more transmission capacity for the Niagara hydroelectric generating facility, Ontario imports, transfers out of Load Zone A21 to the rest of the state, reducing congestion and improving reliability. (See Public Policy Tx Project Wins Key NYISO Endorsement.) The $181 million project is expected to be in service by June 2022.

More: ER18-125-001

WASHINGTON

Bill Implementing Carbon Tax Can't Get Passed in Senate

State Sen. Reuven Carlyle and Gov. Jay Inslee said March 1 that they couldn't get enough votes in the Senate to pass a bill instituting a carbon tax, with Inslee telling the Associated Press they were "one or two votes shy."

The bill also would have needed to pass the House of Representatives before the legislative session ends March 8.

More: The Seattle Times and the Associated Press

Let Industry Lead on Grid Defenses, ex-NSA Cyber Expert Says

Continued from page 1


Murkowski

giving FERC the power to issue mandatory reliability standards (in the Energy Policy Act of 2005) and making the Department of Energy the federal agency in charge of responding to attacks on the grid (in the 2015 Fixing America's Surface Transportation Act).

Robert M. Lee, who founded industrial cybersecurity company Dragos with two other former NSA experts on industrial threats, told the committee that the critical infrastructure protection (CIP) standards mandated by FERC through NERC had made "the North American Bulk Electric System the most resilient and well defended in the world."

But he said FERC and NERC should not issue any new CIP regulations for three to four years. "This would allow companies to catch up with the current regulations … [and] allow the electric asset owner and operator community to spend a period of time innovating and thinking of new best practices informed by experience. At the end of this period DOE, FERC, NERC and the regulated community can then identify best practices and determine if new regulations are appropriate," he said.

"If this recommendation is not palatable, then I would propose an alternative where the regulations are focused instead on program building, such as regulating that a company implement a threat intelligence program, instead of performance-based auditing," he continued. "This would satisfy the potential desire to move regulations forward while allowing the electric community to develop their own ways forward inside of those programmatic bounds."

The problem, Lee said, is that "regulations and standards are the trailing end of best practices and only serve as a base level of security. They are not, nor would any regulation be, adequate in the face of determined adversaries. Malware and vulnerabilities are not the threat. The threat is the human adversary, and we cannot regulate them away."

OT is not IT

Lee and other witnesses emphasized the differences between attacks on utilities' information technology systems and those on operational technology systems such as supervisory control and data acquisition (SCADA).


Sanders

"Fortunately, the successful attacks to date have largely been concentrated on utility business systems, as opposed to monitoring and control systems, in part because the operational technology systems have fewer attack surfaces, fewer users with more limited privileges, greater use of encryption, and more use of analog technology," said professor William H. Sanders, head of the Department of Electrical and Computer Engineering at the University of Illinois at Urbana-Champaign. "However, there is a substantial and growing risk of a successful breach of operational technology systems, and the potential impacts of such a breach could be significant."

Walker, who heads DOE's Office of Electricity Delivery and Energy Reliability, also made the distinction. "Power systems must operate continuously with high reliability and availability. Upgrades and patches can be difficult and time-consuming, with components dispersed over wide geographic regions," he said. "Further, many assets are in publicly accessible areas where they can be subject to physical tampering. Real-time operations are imperative, and latency is unacceptable for many applications. Immediate emergency response capability is mandatory and active scanning of the network can be difficult."

> **"There is a substantial and growing risk of a successful breach of operational technology systems, and the potential impacts of such a breach could be significant."**
>
> **William H. Sanders, University of Illinois at Urbana-Champaign**

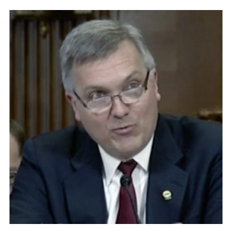
New DOE Cyber Office

Last month, DOE announced it was merging its Infrastructure Security and Energy Restoration (ISER) division and Cybersecurity and Emerging Threats Research and Development (CET R&D) division into the Office of Cybersecurity, Energy Security and Emergency Response (CESER).

Walker said CESER "will enable more coordinated preparedness and response to cyber and physical threats and natural disasters. This must include electricity delivery, oil and natural gas infrastructure, and all forms of generation."

President Trump has requested $95 million in fiscal 2019 for the office "with a focus on early stage activities that improve cybersecurity and resilience to harden and evolve critical grid infrastructure," Walker said. "These activities include early stage R&D at national laboratories to develop the next generation of cybersecurity control systems, components and devices including a greater ability to share time-critical data with industry to detect, prevent and recover from cyber events."

Acts of War


Matheson

Jim Matheson, CEO of the National Rural Electric Cooperative Association (NRECA) and a former congressman (D-Utah), decried "far-fetched scenarios [and] sensationalized claims" about the risks to the grid.

"The scenarios most publicized are rarely reflective of the real threat environment and disproportionately emphasize the highest consequence scenarios that are the least likely to occur," he said. "Many of the more dramatic scenarios would constitute acts of war on the United States and would directly impact more than just the electric sector."

No Cyber Fire Departments

Such an event would call for the National Guard, said Barbara Endicott-Popovsky, executive director of the Center for Information Assurance and Cybersecurity at the University of Washington.

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Let Industry Lead on Grid Defenses, ex-NSA Cyber Expert Says

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Endicott-Popovsky said Congress should pass a bill that would establish National Guard Cyber Civil Support Teams of up to 10 members in every state and territory to serve as first responders following an attack and bridge the gap between federal and non-federal efforts. The cyber CSTs would be under the direction of governors and state adjutant generals, under legislation (H.R.3712) introduced last September in the House of Representatives and referred to the Subcommittee on Military Personnel in October. The bill is modeled after a program created by the Washington National Guard.

"Civilians are used to calling 911 for emergencies of all kinds, but who do you call in the event of a major cyber outage? There are no cyber fire departments," she said. "The [Department of Defense] is prepared to defend their own networks to support their missions, but who will step in on the civilian and private sector sides to restore power, to assist with maintaining our communities? There is no one. This vacuum is a national security threat.

"Public and private, we have two very different missions: The mission of the military is to protect the Homeland, and the mission of private sector to innovate and maintain profitability for the board and shareholders," she continued. "Blending missions is not an easy task, but the time has come where the cost of not integrating resources significantly outweighs the benefits of maintaining independent response plans. This is especially true given the workforce shortage of cyber specialists."

Endicott-Popovsky

Endicott-Popovsky said it will take a national effort comparable to NASA's goal of landing on the moon to fill the shortage of cyber talent. "While cybersecurity education has been called a national priority by some, there still are hundreds of thousands of cybersecurity jobs going unfilled, and the gap will take a long time to close," she said.
The good news: Cybersecurity is becoming a profession, with 32 distinct career paths identified under the National Initiative for Cybersecurity Education (NICE) framework, she said.

How Congress Can Help

In response to Murkowski's question about Congress' next steps, Matheson called for more timely information sharing by government after incidents such as the December 2015 attack on Ukraine's grid.

He also called for legislation allowing the FBI to conduct background checks on utility industry personnel performing critical functions, continued funding for R&D and aid to small and medium utilities for improving their security.

Illinois' Sanders said DOE, the Department of Homeland Security and researchers should focus their R&D and demonstration projects on developing six capabilities: "continuous data collection, fusion of sensor data, visualization, analytics, restoration and post-event tools."

"These capabilities can be achieved only if academia, industry and government work closely together in a focused research and development program," he said.