RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

ISSN 2377-8016 : Volume 2017/Issue 41 October 17, 2017

Spotlight on DC Circuit, FERC After Resiliency NOPR, CPP Repeal

CPP Supporters Hope for Action by DC Circuit

By Rich Heidorn Jr.

Now that EPA has reversed its position on the legality of the Clean Power Plan, some supporters of the program say the appellate court that heard oral arguments a year ago should rule on the issue.

In proposing to repeal the CPP, EPA Administrator Scott Pruitt said Oct. 10 that the Obama administration overreached its legal authority under Section 111(d) of the Clean Air Act by ordering generators to take actions "outside the fence line" of individual generators. (See *EPA to Announce Clean Power Plan Repeal*.)

That was one of the central issues in the appeal that Pruitt, as Oklahoma attorney general, filed along with more than two dozen other states after the CPP was issued in August 2015. In September 2016, the D.C. Circuit Court of Appeals heard oral

Continued on page 39

Perry Defends Call for Coal, Nuclear Supports

'What's the cost of freedom?'

By Michael Brooks and Rich Heidorn Jr.

Energy Secretary Rick Perry | *© RTO Insider*

WASHINGTON — Energy Secretary Rick Perry on Thursday defended his call for price supports for struggling coal and nuclear plants, telling the House Energy Subcommittee "these resources must be revived, not reviled."

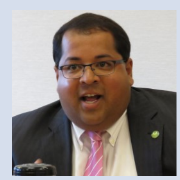
Perry also pushed back on criticism that his Notice of Proposed Rulemaking, which called for "full recovery" of the plants' costs, would undermine competitive markets.

Republicans largely expressed support for the rule. But Perry did little to counter allegations that his action was motivated by President Trump's campaign promises to help the coal industry — repeatedly side-stepping Democrats' questions about the costs of his proposal and the evidence supporting the need for 90 days of on-site fuel. He also contradicted himself on whether the NOPR was a command to FERC

Continued on page 30

FERC Chair Praises Perry's 'Bold Leadership' on NOPR

By Michael Brooks and Rich Heidorn Jr.



Neil Chatterjee | *© RTO Insider*

WASHINGTON — FERC Chairman Neil Chatterjee praised Energy Secretary Rick Perry's "bold leadership" in calling for price supports for coal and nuclear plants but promised the commission's response will be "fuel-neutral" and will not undermine wholesale markets.

Continued on page 32

Unfazed by Obstacles, Clean Line's Skelly Focuses on Future

By Tom Kleckner

Clean Line CEO Mike Skelly in his renovated fire station. | *© RTO Insider*

HOUSTON — When Missouri regulators recently rejected Clean Line Energy Partners' application to build a high-voltage transmission line through the state, it seemed to sound the project's death knell.

After all, it marked the company's third unsuccessful attempt to gain Public Service Commission approval for its 780-mile Grain Belt Express, a $2.3 billion initiative that would deliver 4,000 MW of wind power from western Kansas through Missouri and Illinois to the Indiana border.

The company's first attempt in 2015 was shot down after the PSC determined the project did not provide enough benefits to Missouri consumers. A second attempt last year failed on a technicality. The project has already been approved by Kansas and Illinois.

But Michael Skelly, Clean Line's founder and president, was undeterred. Moments after the PSC determined that Grain Belt

Continued on page 37

Also in this issue:

10837 Deborah Drive ◻ Potomac, MD 20854 ◻ (301) 299-0375 ◻ info@rtoinsider.com ◻ www.rtoinsider.com ◻

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

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

Deputy Editor / Senior Correspondent
Robert Mullin 503-715-6901

Production Editor
Michael Brooks 301-922-7687

Contributing Editors
Julie Gromer 215-869-6969
Peter Key

CAISO/West Correspondent
Jason Fordney 571-224-8960

ISO-NE/NYISO Correspondent
Michael Kuser 802-681-5581

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Rory D. Sweeney 717-679-1638

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions and Advertising

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

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

Subscription Rates:

Payment Frequency	PDF-Only	PDF & Web
Annually:	$1,350.00	$1,650.00
Quarterly:	380.00	475.00
Monthly:	150.00	175.00

See details and Subscriber Agreement at rtoinsider.com.

IN THIS WEEK'S ISSUE

Counterflow
By Steve Huntoon

More Smoking Guns for the Clunkers

By Steve Huntoon


Huntoon

My last couple of columns have explored the Department of Energy's "Cash for Clunkers" proposal. The first column discussed how it will cost tens of billions of dollars and subsidize *less* reliable generating resources to suppress *more* reliable resources.[1] The second column showed that the proposal is the direct result of meetings between President Trump and Robert Murray, coal mine owner and major fundraiser for the president's campaign,[2] not some deliberative process involving well-informed, well-intentioned people.

Robert Murray's Confirmation

A shout-out to Murray for providing a smoking gun one day after my last column ran, confirming that the DOE proposal is all about selling more of his coal to FirstEnergy power plants, one way or another.[3]

1 in 5,000, and Then Some

Some folks may still think that the situation can't possibly be that outrageous. The DOE proposal can't be that devoid of merit.

Wrong.

The smoking gun below is from ReliabilityFirst, the regional reliability organization responsible for reliability in the Mid-Atlantic and Midwest states (the states that are the focus of the DOE proposal).[4]

Please bear with me in explaining this graphic. It's displaying the winter. The leftmost column is showing generating resources. The next column is showing possible reduction in those resources due to resource outages, based on the last five winters (including the polar vortex). The percentages on the left are the chance of cumulative outages exceeding the associated outage quantity.[5]

The biggest cumulative reduction in resources has a 0.2% chance of occurring. That is one in 500.

OK, now skip the 50/50 Demand column and look at the 90/10 Demand column. That reflects a one-in-10 chance of the coldest weather.

Please note that resources at a one-in-500 worst case (the second column) are still much *more* than the peak demand in the one-in-10 worst case (the last column).

In other words, combined there is much less than a one-in-5,000 (500 x 10) chance of peak demand exceeding resources in the winter.

And there's more!

What if that less-than-one-in-5,000 situation were to occur? Fuel supply interruption is unlikely to be a major factor.[6] And RTOs like PJM have tools to avoid customer impact, such as public appeals for conservation and voltage reductions.[7] And any resource-demand shortage would last only hours, not weeks or of course months.[8]

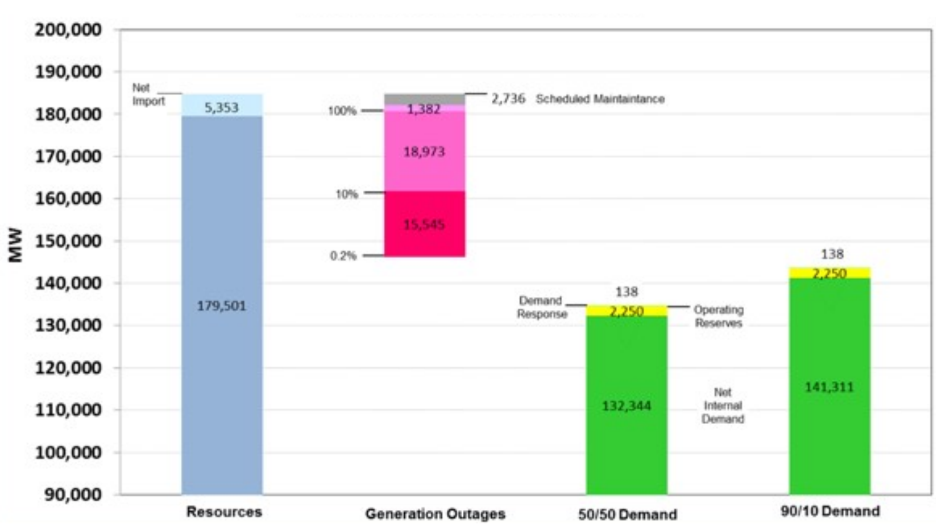
The DOE proposal is much ado about nothing.

The Worm Will Turn

Here's the third smoking gun. If FERC goes forward with subsidizing certain resources for an insignificant quality like fuel supply on site, it should recognize really important qualities like environmental/public health damage.[9] In the case of coal, the National Research Council of the National Academies estimates that coal generation causes pollution damage averaging $32/MWh.[10]

This means coal resources should pay $32/MWh for their generation, to be subtracted from whatever revenues they otherwise would receive. The payments should be distributed to those hurt by coal generation.

This administration won't do that, but no administration is forever. Once the precedent is set for FERC to put its thumbs on the scales, coal better hope that the worm never turns.



Winter 2016/17 PJM outage risk | *PJM*

Steve Huntoon is a former president of the Energy Bar Association, with 30 years of experience advising and representing energy companies and institutions. He received a B.A. in economics and a J.D. from the University of Virginia. He is the principal in Energy Counsel, LLP, www.energy-counsel.com.

[1] https://www.rtoinsider.com/ferc-baseload-power-energy-department-doe-76332/

[2] https://www.rtoinsider.com/murray-energy-department-of-energy-76903/

[3] Murray said he had pressed Trump and Energy Secretary Rick Perry to have the secretary order financial support for at-risk coal plants using DOE emergency authority, but department and White House lawyers ruled that out. "They didn't want to declare the emergency," he said. "It was a low point because we worked hard at it and knew it was needed.

"They're doing it in a different way," Murray said. "Now we have another approach that's in use to get to the same point." https://www.eenews.net/energywire/2017/10/11/stories/1060063287

[4] https://www.rfirst.org/reliability/Documents/2016-17%20RF%20Assessment-Winter%20Resource.pdf

[5] ReliabilityFirst says, "To the left side of the range of random outages are probability percentages related to the amount of random outages that equal or exceed the amount of outages shown above that line on the outage bar."

[6] "Between 2012 and 2016, there were roughly 3.4 billion customer-hours impacted by major electricity disruptions. Of that, 2,382 hours, or 0.00007% of the total, was due to fuel supply problems." http://rhg.com/notes/the-real-electricity-reliability-crisis.

[7] Described in excruciating detail in PJM's Manual 13, http://pjm.com/-/media/documents/manuals/m13.ashx.

[8] In the polar vortex, the generation emergencies in PJM aggregated 20 hours. http://pjm.com/-/media/committees-groups/committees/elc/postings/performance-assessment-hours-2011-2014-xls.ashx?la=en.

[9] An elaborate and persuasive discussion of this proposition is provided by Professors Meredith Fowlie and Maximilian Auffhammer: https://theconversation.com/why-rick-perrys-proposed-subsidies-for-coal-fail-economics-101-83339.

[10] https://www.nap.edu/catalog/12794/hidden-costs-of-energy-unpriced-consequences-of-energy-production-and (page 92, converting from kilowatt-hours to megawatt-hours). Damage from natural gas pollution is $1.60/MWh (page 118). Damage from nuclear pollution is small (page 150). These figures do not include greenhouse gases.

Infocast Transmission Summit West

Policy Biggest Obstacle for Storage, Panel Says

By Jason Fordney

Left to right: panel moderator Luke Martin of ScottMadden; Tom Dagenais, DATC; Kiran Kumaraswamy, AES; Jin Noh, California ESA. | *© RTO Insider*

SAN DIEGO — The electricity sector continues to identify possible applications for energy storage while costs for the technology steadily decline, but the lack of cohesive federal, state and local policy remains the chief obstacle to integration, a panel of experts said Wednesday.

"The technology piece has caught up. What we cannot afford to do is let the policy drag it down," Kiran Kumaraswamy of AES Energy Storage said during a panel discussion at the Infocast Transmission Summit West. Industry and policymakers can develop a framework for adopting storage once they determine the magnitude and type of need for the technology, he said.

Storage has not traditionally been seen as a workable solution to solving locational reliability needs on the transmission grid, and there are questions as to whether it should be regulated as a generation or transmission/distribution asset. The U.S., especially CAISO, is in a leadership position as far as deploying storage, "but the rest of the world is catching up," Kumaraswamy said.

Storage can also defer transmission investment, and "the ISO has been very progressive in considering non-wires alternatives," he said.

CAISO recently launched a yearslong effort to develop a load-shifting product for energy storage, the third phase of its Energy Storage and Distributed Energy Resources (ESDER) initiative. (See CAISO Load-Shifting Product to Target Energy Storage.)

Even in situations in which conventional generation would be much cheaper, California regulatory policy and public opinion are driving storage applications. After CAISO recently performed a study finding that the $299 million proposed Puente Power Project is the cheapest alternative to energy storage and distributed energy solutions costing up to $1.2 billion, the California Energy Commission still indicated that it might not approve the plant. (See CEC Members Recommend No-Go for Puente Plant.)

There is "a very good working relationship between renewables and energy storage," according to Tom Dagenais of Duke-American Transmission Co., a joint venture between Duke Energy and American Transmission Co. created to develop new transmission projects — such as the Zephyr line to carry wind energy from Wyoming to California, and the San Luis transmission project in California's Central Valley.

Dagenais cautioned that integrating energy storage is a challenge, and that the decisions being made today as the technology enters the market will set the tone for how it is perceived in the future.

"If we screw this up, there is going to be a lot of fingers pointed and a lot of questions," he said.

"It is a question of what type of capacity. There is a major need for flexibility capacity and opportunities to save ratepayer money."

Jin Noh, California Energy Storage Alliance

FERC last November issued a Notice of Proposed Rulemaking that would require each RTO and ISO to recognize the physical and operational characteristics of storage, and accommodate storage and aggregated distributed resources in organized markets. (See FERC Rule Would Boost Energy Storage, DER.)

But the agency lost its quorum shortly after the proposed rule was issued, and it is unclear whether the new commission will act on it. It is also unknown how FERC will view storage as the commission becomes embroiled in controversy over Energy Secretary Rick Perry's new proposed rule designed to bolster coal-fired generation.

Idaho Public Commissioner Kristine Raper asked the panel how a state like hers, which is long on capacity and has an abundance of hydroelectric generation, could take advantage of energy storage.

Jin Noh of the California Energy Storage Alliance noted that the state has sufficient capacity but is still pursuing energy storage. "It is a question of what type of capacity," Noh said. "There is a major need for flexibility capacity and opportunities to save ratepayer money."

Dagenais said: "Idaho is in a pretty unique situation," adding that many other states have a rapidly changing resource mix. He said that storage is still something worth looking into to cut costs and reduce use of lower-efficiency generation units at peak times.

Infocast Transmission Summit West

EIM Affecting Western Transmission, Resource Planning

By Jason Fordney

SAN DIEGO — The CAISO-run Western Energy Imbalance Market (EIM) has increased the operational flexibility of the region's utilities and is leading to changes in resource procurement in states outside California, utility representatives said last week.

Speaking on a panel at Infocast's Transmission Summit West, Matt Lecar, Pacific Gas and Electric principal of ISO relations and FERC policy, said "one of our big challenges is managing solar generation, and the EIM has been extremely valuable" by absorbing generation and reducing curtailment of renewables.

"We get to use more of our clean energy, more of the time," Lecar said.

The EIM is also serving as a "proving ground as to how create a governing structure for a regional RTO," he said, creating more planning certainty for entities in the West.

"The key here is to develop a culture of trust," he said, adding that the EIM is proving the benefits of a regional market, and "the biggest enemy of trust is uncertainty."

Even though the EIM is presently only a balancing market, it is already having an effect on resource planning in other states, NV Energy Director of Energy Market Policy Lauren Rosenblatt said.

"Now Nevada is highly affected by the regional resource mix in ways it wasn't before," she said. Nevada gets a lot of negatively priced solar energy from California, so power suppliers are less likely to build solar photovoltaic because they have the opportunity to obtain solar output from next door.

Idaho Power Vice President of Power Supply Tess Park said it is a positive that the EIM doesn't require a participant to stay in the market for years, and if things don't go well, "there is an out."

The EIM has grown since its launch in November 2014, and panel participants said it has allowed energy resource-rich areas in the western interior to more effectively link up with the load-heavy population centers on the California coast. CAISO said the EIM produced $39.52 million in benefits for its participants in the second quarter, with CAISO gaining the largest share. (See *CAISO Leads EIM Q2 Benefits, Exports*.) As of the end of the second quarter of this year, benefits have been $213 million from more efficient dispatch, reduced renewable curtailment and reduced need for flexible ramping capacity, the ISO has said.

CAISO Strategic Alliance Director Don Fuller said the EIM has brought better economics and resources to electricity sector participants in the West. By taking advantage of excess capacity on the existing transmission system, the EIM helps avoid building of new transmission lines and makes for a more efficient regional grid.

"The idea was to take advantage of unused

Continued on page 6

Left to right: *RTO Insider*'s Jason Fordney moderates the panel with Florio, Raper and Burns. | © *RTO Insider*

Current and Former State Regulators Discuss CAISO Regionalization, Other Topics

Three former and current state regulators on Oct. 12 discussed regionalization of CAISO, changes at the federal level and other topics at a panel discussion moderated by *RTO Insider*'s Jason Fordney at Infocast's Transmission Summit West in San Diego.

Idaho Public Utilities Commissioner Kristine Raper, Arizona Corporation Commissioner Bob Burns and former California Public Utilities Commissioner Mike Florio generally agreed that until the governance structure of a new RTO is worked out, it will be difficult to resolve other disagreements, such as how transmission costs are allocated.

California entities are worried that the state will lose control over energy planning, and neighboring states don't want to have to conform to California's policies. The California State Legislature is set to take up regionalization again in January after the effort stalled this year.

Infocast Transmission Summit West

Panelists: CPP Repeal to Have Limited Impact in West

By Jason Fordney

SAN DIEGO — The fate of the West's coal-fired power was already sealed prior to EPA's announcement that it will seek to repeal the Clean Power Plan, a panel of industry participants said last week at Infocast's Transmission Summit West.

But those panelists also agreed there has not been adequate consideration of the impact of coal retirements on the region's grid. The Trump administration argued that former President Barack Obama's call for switching to more natural gas and renewable generation caused the agency to exceed its authority. (See *EPA to Announce Clean Power Plan Repeal*.)

Speaking for ITC Grid Development, consultant Ron Belval said that while federal regulation affects coal-fired power, "I think it is going to be an economic decision; the wheels have already been set in motion" by low gas prices and more penetration of renewables. There might be some extension of the life of existing plants, but they will still be retired, he said.

The Western transmission network was designed for a traditional resource mix serving certain load centers, including areas that are served by coal, gas and nuclear, Belval said. The retirements of coal-fired plants will dramatically change how the system will be utilized, but the characteristics of the new system have not been identified.

Belval noted that there are also the requirements of California's "duck curve" to consider. It is unclear what the mix of new resources will be or exactly where they will be deployed, he said, and the grid has needs in terms of frequency response and voltage regulation.

By 2025, about 5,000 MW of coal-fired capacity is scheduled for retirement in the West — basically all the large plants, according to Keegan Moyer, a principal with Energy Strategies.

"That is most of it; there is not that much more after that," he said, adding that there is a not a "cookie-cutter" strategy for replacing those resources.

Left to right: Panel moderator DATC Vice President Laurie Dunham; Ron Belval, Belval Connections; APS Director Brian Cole; and Energy Strategies Principal Keegan Moyer. | *© RTO Insider*

The retirements will free up transmission capacity that could be used by other resources, creating opportunities for new entrants, panelists said.

The transmission system is designed around natural gas plants that have also served to balance renewables and can quickly ramp up, and operators also are used to certain conditions, Belval said. "I suppose you could replace the gas resources, but I don't know what those would be," he said, noting that other resources are "not tried and true."

"You have got to replace those with something that you know works," and those resources need to be modeled in the operational time frame, he said.

Brian Cole, director of engineering at Arizona Public Service, said that at his utility, "the schedule for shutting down the older [coal] plants had already begun to be put in place. The Clean Power Plan just helped cement that and make that happen." System operators are seeing the impact of renewables at the transmission and distribution levels, he said.

"We are trying to get our arms around it," he said, adding that the removal of baseload generation also requires new ramping capabilities.

The CPP's repeal effort has been accompanied by Energy Secretary Rick Perry's recent directive that FERC ensure cost recovery for at-risk coal and nuclear generation in organized markets, representing an additional seismic shift in direction at the federal level. (See *Perry Orders FERC Rescue of Nukes, Coal*.) But panel participants indicated that the proposals are a long way from causing a surge in demand for coal-fired energy resources in Western states.

EIM Affecting Western Transmission, Resource Planning

Continued from page 5

transmission, so it worked without new transmission," Fuller said, adding that as new market participants bring transmission in, it helps all EIM entities move energy around.

The EIM took advantage of CAISO's existing market platform and allowed easy entry and exit, allowing individual balancing authorities to retain control over their assets and join when they wanted. That has been a "key factor" in its growth, he said.

The market "has been another tool in our effort to manage renewables" and allows neighboring states to take advantage of low-cost power being produced in California, Fuller said.

Portland General Electric on Oct. 1 became the latest utility to begin operating in the EIM, and others have agreed to join but have not yet begun participating. Active participants include PacifiCorp, NVE, Puget Sound Energy and Arizona Public Service. Idaho Power and Powerex are due to join in 2018; Seattle City Light, the Los Angeles Department of Water and Power, and Balancing Authority of Northern California in 2019; and Salt River Project in 2020.

ERCOT NEWS

Vistra Energy to Close 2 More Coal Plants

By Tom Kleckner

Vistra Energy announced Friday it will close two additional coal-fired plants, taking another 2,300 MW of capacity offline and slashing its coal portfolio by more than half.

The retirements of Big Brown, north of Houston, and Sandow, northeast of Austin, will leave Vistra's Luminant generating subsidiary with just two operational coal plants rated at a combined 3,850 MW. Vistra announced Oct. 6 it would be retiring its three-unit, 1,800-MW Monticello plant in East Texas. (See *First Shoe to Drop? Vistra to Retire 3 Texas Coal Units*.)

CEO Curt Morgan again blamed the "economically challenged" environment the plants face in the ERCOT market. The company said sustained low wholesale power prices, an oversupply of renewable generation and low natural gas prices contributed to the decision.

"Though the long-term economic viability of these plants has been in question for some time, our yearlong analysis indicates this announcement is now necessary," Morgan said.

ERCOT's most recent Capacity, Demand and Reserves report indicated the ISO had an 18.9% reserve margin for next summer, with margins remaining above 18% the following three years. A revised CDR report will be released in December.

"The market will tighten from a reserve margin perspective, but it remains to be seen if on-peak forwards will rise in response," Kevin Vo, a research analyst with Tudor, Pickering, Holt, & Co., told *RTO Insider*. "We don't believe off-peak pricing would be affected due to the large amount of wind generation."

The Vistra retirements include the 600-MW Sandow Unit 5, which went online in 2009 and has a 75% capacity factor. Only Luminant's twin-unit Oak Grove plant, which began operations in 2010, is newer.

Sandow was built to serve a nearby Alcoa smelter, which was closed in 2008. Shortly before making its announcement, Vistra agreed to an early settlement that terminates a long-standing power and mining agreement with the aluminum company.

A Luminant spokesperson said once the contract was terminated, it became clear the Sandow units were not economical in the ERCOT market.

Big Brown plant | *Vistra Energy*

Sandow plant | *Vistra Energy*

"The contract has helped shield Sandow from significant exposure to the downturn in the wholesale power market," the company said in a press release.

"Sandow's retirement was a surprise but highlights that it is hard for any coal plant to make money in Texas right now," Ko said. "If you are a coal plant generator, you're waiting to see if prices will respond. If prices don't rise meaningfully or any price increase isn't sustained, we would not be surprised if there are further coal plant retirement announcements."

The Three Oaks mine, which supports the plant, will also be closed.

Luminant has filed a 90-day notice of suspension of operations with ERCOT. The plant will cease operating Jan. 11 if the ISO's reliability review shows the units are not needed.

Big Brown is the oldest coal plant in Luminant's fleet, with its two units having begun operations in 1971 and 1972. The units are together capable of generating 1,150 MW and have a combined capacity factor of 59%. Both units burn lignite supplemented by Powder River Basin coal. The nearby Turlington mine that supplies the plant was already scheduled to wind down operations by the end of this year.

Vistra said it would explore a sales process for the site during ERCOT's notification period. The company filed a 120-day suspension noticed with the ISO to allow for a "more complete sales process." With ERCOT's approval, the plant will cease operations on Feb. 12 if it has not been sold.

Luminant said about 650 employees will be affected by the plant and mine closures.

The company's 2,250-MW Martin Lake plant in East Texas is now the fleet's oldest, its three units having gone into service in 1977, 1978 and 1979. Luminant also has 7,500 MW of natural gas capacity and 2,300 MW of nuclear capacity.

ERCOT News

Spike Sends ERCOT Houston Prices Past $1,000/MWh

By Tom Kleckner

ERCOT's Houston Hub saw real-time prices spike as high as $1,251/MWh last week during an early fall heat wave.

Hub prices first cracked $1,000/MWh during the 15-minute interval ending at 1:45 p.m. on Oct. 9, and then again during each of the 11 intervals between 2:30 and 5 p.m. The systemwide hub average peaked at $520.59/MWh during the 3:15 p.m. interval.

According to ERCOT data, the Houston Hub has now produced 47 intervals of $1,000/MWh this year, That's the most since 2011, the first full year of the nodal market, when the hub recorded 163 high-priced events. It only had 87 occurrences in 2012-2016.

| ICF

Congestion has long been an issue in the Houston zone, but the high temperatures caught the market with several plants on maintenance outages.

Speaking during a webinar last week, Dinesh Madan, an ICF technical director, said scarcity pricing has been "almost missing from this market." Madan pointed to a volatile market, thanks to an overabundance of wind energy and short load forecasts.

"ERCOT is a weather-and-wind story now," Madan said. "In 2016, the story was wind. In 2017, the story was weather."

In 2016, wind resources generated 2,024 MW more than their forecasted output coinciding with the summer peak. In 2017, the market's peak load was 3,428 MW below forecast, thanks to a milder summer. With ample reserves (and lower loads), ERCOT was able to withstand 2016 and 2017 peak loads despite generation outages exceeding forecasts by 1,780 MW and 2,713 MW, respectively, during each summer's peak.

Last Monday's spike came as Texas temperatures soared into the mid 90s. The ISO set a new record for October peak demand at 62,263 MW — just above projections — during the hour ending at 5 p.m., breaking the previous mark set the year before by more than 2.3 GW.

Houston Hub prices peaked at $34.11/MWh last Tuesday, when temperatures and ERCOT load both dropped.

Reservoir of Retirements

During the same webinar last week, ICF Senior Vice President Judah Rose also addressed Vistra Energy's recent decision to retire three aging coal-burning units in East Texas. (See First Shoe to Drop? Vistra to Retire 3 Texas Coal Units.)

He referred to a "reservoir" of potential retirements among ERCOT's coal fleet, driven by fat reserve margins, low gas prices and cheaper renewable resources. Rose also pointed out that many of the coal plants, once reliant on cheap, local lignite — including Vistra's Monticello plant — now depend on Powder River Basin coal brought in on rails from the Rocky Mountains.

"Almost ironically, these plants are facing the least environmental pressure in a long time," Rose said, referring to the Trump administration's efforts to roll back the Clean Power Plan. (See EPA to Announce Clean Power Plan Repeal.)

He said the Energy Department's recent Notice of Proposed Rulemaking to FERC to support out-of-market baseload plants would likely have little effect on Texas coal units, as the agency has no jurisdictional authority over ERCOT.

Any FERC policy "will not provide additional revenue," Rose said. "The exit of these plants will be related to low power prices."

Rose said ICF will be watching ERCOT's reserve margins, which the ISO forecasts will be 16.3% next year. The firm expects that margin to dip below the planning reserve margin of 15.6% in 2019.

"That's significant, because generally, when you start getting below 15% in markets, you have the potential for all hell breaking loose," he said. "You get a lot of potential for price spikes."

The Monticello retirement may provide $1 to $2/MWh of upside in scarcity equilibrium in 2019, Rose said.

ERCOT NEWS

Texas PUC OKs Settlement in Oncor-Sharyland Asset Swap

By Tom Kleckner

The Public Utility of Commission on Wednesday approved a settlement in Oncor's proposed swap of more than $400 million in assets with Sharyland Utilities, paving the way for the two parties to complete the transaction (Docket 47469).

The exchange will result in Oncor acquiring 54,000 retail distribution customers and assets from Sharyland, in exchange for 258 miles of Oncor transmission lines in West and Central Texas. The PUC's approval would also dismiss Sharyland's current rate case, providing "significant rate relief to our customers," according to the utility's CEO, David Campbell.

In 2015 the commission opened an inquiry into Sharyland's rates, which spiked following the utility's 2010 acquisition of a bundled package of financially troubled electric cooperatives. Sharyland is owned by the Hunt family of Dallas, which failed in a 2016 bid to buy Oncor.

"The Hunt organization and Sharyland took a lot of arrows from customers and others, for problems that really weren't of their making," Commissioner Ken Anderson said. "They were faced with an intractable problem. … This will solve that problem. Oncor didn't have to do this. It couldn't have happened but for the agreement of everybody."

The agreement also avoids an expected rate increase for Sharyland's retail customers in South Texas.

"Ultimately, the proposed transaction seeks to resolve the rate disparity that currently exists between Sharyland's high retail electric delivery rates and those of Oncor" and other ERCOT transmission and distribution utilities, the order said.

The commission approved Sharyland's request to recover up to $17 million in transition costs for the proposed transaction, although it directed the utility to use its "best efforts" to sell any assets not being exchanged and to minimize employee-related transition costs.

The PUC also approved the incorporation of Sharyland's energy efficiency cost recovery factor (EECRF) and transmission cost recovery factor (TCRF) regulatory assets or liabilities into Oncor's EECRF and TCRF.

Oncor, Sharyland representatives discuss their settlement with PUC staff.

Oncor plans to make its 2018 EECRF effective March 1, 2018, and will include a refund of $6,097,744 for its over-recovered 2016 energy efficiency costs. The transaction, expected to close before March 1, will result in a credit of $243,199 for Sharyland's over-recovered 2016 energy efficiency costs. That total will be combined with Oncor's EECRF and be refunded to the appropriate Oncor rate classes.

Oncor is already the largest utility in Texas, with 3.4 million wholesale and retail customers.

The commission's approval led to a round of back-patting among the parties and commission staff.

"It's been a long process, with a lot of tricky issues we didn't anticipate," said Vinson & Elkins' Matt Henry, Oncor's legal counsel. "Staff worked hard to help us fight through the things. Working with Sharyland and their team, there was never a point we didn't find an obstacle we couldn't work through."

"Matt is probably just happy he finally has a change-in-control agreement," said PUC Executive Director Brian Lloyd.

Left to right: PUCT Commissioners Ken Anderson, Chair DeAnn Walker and Brandy Marty Marquez.

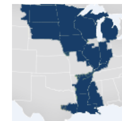
Schedules Set in LP&L, Sempra-Oncor Cases

The commissioners set tentative hearing dates in a pair of upcoming high-profile cases that will keep them busy well into 2018.

During an Oct. 9 prehearing conference, parties in Lubbock Power & Light's plan to migrate part of its load from SPP into ERCOT agreed to Jan. 17-18, 2018, hearing dates (Docket 47576).

Lubbock on Sept. 1 filed its formal application to integrate 470 MW of its load with ERCOT by June 2021. That load is currently served through a wholesale contract with SPP member Southwestern Public Service; the contract expires May 31, 2021.

Another prehearing conference was scheduled Monday for Sempra Energy's attempted acquisition of Oncor (Docket 47675). The PUC has blocked off Feb. 21-23 for a hearing on the merits.



MISO NEWS

Dynegy: MISO LSE Load Forecasts Require Tune-up

By Amanda Durish Cook

"None of us like penalties, of course, but I think we need to put on our thinking caps and find a way to review whether a load-serving entity came close to its planning reserve margin."

Mark Volpe, Dynegy

CARMEL, Ind. — After criticizing Ameren Illinois for miscalculating its summer peak load forecast, Dynegy last week called on MISO to develop a new process for verifying load forecasts produced by load-serving entities.

Mark Volpe | © *RTO Insider*

Dynegy's Mark Volpe said that while Zone 4 in Southern Illinois represents just 8% of total MISO capacity, it showed the largest under-procurement in the RTO's Planning Resource Auction, when reserves came up 467.8 MW short of requirements when the summer peak occurred July 20.

The reason, according to Dynegy: Ameren's portion of the Zone 4 load forecast for the July 2017 peak dropped 484 MW, or 6.4%, from the previous year to 7,069 MW. That led to an overall zone peak forecast of 8,925 MW, down 481 MW, compared with last year's actual peak of 9,500 MW.

Dynegy said that none of the other zones in MISO showed a similar drop in load forecast.

"This raised our eyebrows at Dynegy," Volpe said during an Oct. 11 Resource Adequacy Subcommittee meeting.

"We questioned MISO repeatedly on the reasonableness of the forecast, and MISO continually defended the Ameren Illinois load forecast as plausible and reasonable, given gains related to investment in energy efficiency programs, a decrease in commercial and industrial load, and an overall downturn in the economy," Volpe said.

As required by its Tariff, MISO asks resources to provide forecasts of annual coincident, monthly non-coincident and local resource zone peak demand for use in producing annual load forecasts.

"MISO should have worked closer with Ameren to resolve what we see as an understatement of load forecast in Zone 4. Given the benefit of hindsight of the July 20 peak load … it seems to us that our concerns were pretty valid," Volpe said.

Consumers Energy's Jeff Beattie pointed out the Zone 4 planning reserve sharing group easily compensated for the 468-MW shortage.

"To me, that's one of the benefits of being in an RTO," Beattie said.

"You're right — from a macro perspective, things are fine," Volpe said, adding that he was more interested in the year-over-year changes to load forecasts.

Volpe said MISO does not currently have provisions to perform an after-the-fact examination of forecasts provided by LSEs. He suggested that an independent third party could provide a "look back" of the load forecasts to check for accuracy.

"None of us like penalties, of course, but I think we need to put on our thinking caps and find a way to review whether a load-serving entity came close to its planning reserve margin," Volpe said. "We're concerned with overall system reliability, and we have to realize that this impacts all connected to the transmission system."

Minnesota Public Utilities Commission staff member Hwikwon Ham asked Volpe who would pay for the third-party review. Volpe said costs would have to be worked out if MISO pursues the proposal.

MISO Executive Director of Strategy Shawn McFarlane said the RTO will address the presentation at the November meeting. Kevin Sherd, MISO director of forward operations planning, said the RTO continues to support its existing load forecasting process.

"Quite frankly, we think the forecasts are good on a reasonable, one-year-out basis," Sherd said.

Improving the Independent Load Forecast?

Volpe suggested that Purdue University — the same third party that produces independent load forecasts used to evaluate the MISO's own predictions — could verify LSE load forecasts.

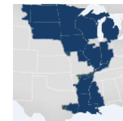
But MISO said last month that after three years of using forecasts prepared by Purdue, the process could use improvement, although it did not propose possible changes.

The university's State Utility Forecasting Group generates forecasts for all 15 MISO states using public data from the Energy Information Administration. The forecast includes summer and winter values for annual energy use in MISO's 10 local resource zones and aggregate, coincident and non-coincident peak demand predictions for each zone. MISO is nearing the end of a three-year contract with Purdue to provide the forecasts.

MISO said that after three iterations of the third-party forecasts, it has refined its methodology based on stakeholder wishes, leading to use of Applied Energy Group and electric generation expansion analysis system data to create predictions of generation and renewable growth, instead of simply relying state mandates and goals.

"We've used the forecast to date for comparison," MISO Director of Planning Jeff Webb explained earlier this month, noting that the RTO first consults resource adequacy requirements under Module E of its Tariff, then compares the independent forecast against aggregated forecasts submitted by LSEs and transmission owners to determine reserve requirements.

MISO News



3-Degree Forecast Error Triggered MISO September Emergency

By Amanda Durish Cook

CARMEL, Ind. — MISO officials said a temperature forecast short by just 3 degrees Fahrenheit triggered a maximum generation event Sept. 22.

Tim Aliff | © *RTO Insider*

Tim Aliff, MISO director of interconnection and planning, said that if the RTO misjudges its temperature forecast by even 1 degree, it either underestimates or overshoots its load forecasts by about 1 GW. On Sept. 22, it expected the footprint to top out at 89 F, instead of the actual high of 92 F, he said.

"That can be a big impact from a load perspective. Those 3 degrees might not feel like much outside, but it caused us to be off by about 4 GW," Aliff said during an Oct. 12 Market Subcommittee meeting.

"Ninety degrees in September isn't all that odd, but 90 degrees in late September is odd," he added.

MISO emergency conditions Sept. 21-25 were the result of a combination of record temperatures, high load, and seasonal and forced generation outages. (See *MISO Capacity Easily Exceeds Predicted Winter Peak*.)

On the day of the maximum generation event, MISO had 4.6 GW of stranded capacity due to forced and planned outages and derates. Additionally, 1.1 GW of generation tripped offline suddenly. Aliff pointed out that during the emergency conditions, MISO South was still recovering from the impacts of Hurricane Harvey.

"It's kind of unusual on a Saturday to get into a max generation situation," Aliff said of Sept. 23, which also fell under the maximum generation warning. "Shoulder months can be challenging, so we continue to review what we need to do to reduce these challenges, if you will."

Michigan Public Service Commission staffer Bonnie Janssen pointed out that by late September, school is in session, which contributes to load.

Xcel Energy's Kari Clark asked whether MISO could make transmission constraints more visible to market participants during emergency conditions so generators can better understand if their megawatts are unlikely to be able to aid an emergency.

"If we know that we could help you, that would be helpful in our processes," Clark said.

Aliff said Clark's suggestion was useful and that he would take it back to his team.

Minnesota Public Utilities Commission staff member Hwikwon Ham asked if MISO has identified a possible transmission solution that would have moderated the situation. Aliff responded that it had not investigated but could look into it.

The September emergency marks MISO's second maximum generation event of the year. On April 4, MISO called up load-modifying resources for the first time in 10 years in the face of a similar blend of unseasonably high loads coupled with a large number of generation and transmission outages. (See "Several Factors in Spring MISO South Maximum Generation Event," *MISO Market Subcommittee Briefs*.) MISO did not have to shed load during the September emergency.

MISO Gets FERC OK to Alter Reserve Requirement Modeling

By Amanda Durish Cook

FERC on Wednesday granted MISO a six-month reprieve from a Tariff provision requiring it to include minimum zonal reserve requirements in its modeling of broader system reserve requirements.

The RTO currently calculates minimum reserve requirements using offline studies conducted three days in advance of a day-ahead market run, but it has said that study results aren't always accurate because actual operating conditions, including transmission constraints, can deviate from original study assumptions.

A case in point: In early April, scarcity pricing was triggered in MISO because an offline study predicted an 84-MW minimum contingency reserve for Zone 6 covering Indiana and a slice of Kentucky, but it failed to account for actual transmission and generation outages modeled in the day-ahead process. Generation and transmission outages in MISO caused an outflow of energy from Zone 6, creating scarcity conditions for reserves and sending prices as high as $1,100/MWh.

In mid-July, MISO said it was evaluating changing the algorithm behind its minimum reserve requirement to reflect energy flow constraints. (See *MISO Ponders Reserve Scheduling Fix*.)

In its filing, the RTO told FERC it needed a waiver of "inflexible" offline studies while it holds stakeholder meetings exploring an additional modeling step to account for constraints and prepares a Tariff filing. It also noted that it could decide to permanently remove offline studies from the process.

MISO filed for the waiver last month, and the commission acted quickly given that the RTO has entered its shoulder season typified by planned outages (ER17-2466).

"MISO requests expeditious action on this waiver request because the conditions that could potentially lead offline studies to set minimum reserve requirements have previously occurred in the months of October and November," FERC said.

The waiver remains in effect until April 12, 2018.

FERC allowed the waiver on the grounds that it will remedy current reserve price distortions through "ineffective constraint relief when minimum reserve requirements do not properly reflect real-time non-deliverability of reserves" and "protect the markets from price signals that do not properly reflect or resolve real-time reserve deliverability issues."

MISO NEWS

WEC Takes Stab at MISO Behind-the-Meter Definition

By Amanda Durish Cook

CARMEL, Ind. — WEC Energy Group uncovered a Tariff inconsistency while it was developing a proposal to improve MISO's behind-the-meter generation participation rules, a company representative said last week.

WEC's Chris Plante said MISO's definition of what constitutes a network resource, defined in Module B of the Tariff, doesn't recognize all capacity acquired under Module E, which covers the procurement of resource adequacy (RA).

Chris Plante | *© RTO Insider*

Module B does not allow a network customer to generically claim the MISO energy market or capacity market as its network resource, thus technically excluding the customer from counting unregistered BTM generation — which does not have existing transmission service — toward RA requirements, Plante said during an Oct. 11 Resource Adequacy Subcommittee meeting. However, Module E currently allows those resources to be counted as capacity.

To reconcile the discrepancy, Plante suggested that MISO's definition of "uppercase," or registered, BTM generation be limited to the following categories:

- Network resources behind the market delivery point;
- Resources behind the market delivery point participating in the market; and
- Resources behind the market delivery point that causes flow on the transmission system.

Plante proposed that any resource be required to register as a network resource with MISO before it can fulfill capacity obligations. The proposal aligns with a plan the RTO is already formulating through planned implementation of a one-time deliverability test for BTM generators that could trigger a requirement to acquire network service in an upcoming capacity auction. (See MISO Proposes Deliverability Rules for Behind-the-Meter Capacity.) Unregistered BTM generators currently enjoy identical treatment to those generators registered as a network resource without having to register with MISO, something the RTO aims to change.

Plante said MISO's "lowercase" BTM generation — resources not required to register — should be limited to those resources located behind the retail meter and used by a retail customer only to manage load "at the same electrical location," Plante said. Such resources would not have to respond to emergency conditions.

"We just want comparable treatment among all network resources," Plante said. "We don't believe just listing the MISO market as your network resource is appropriate," according to Module B of the Tariff, Plante said.

Customized Energy Solutions' Ted Kuhn asked if network customers would now have to enter the capacity auction with a resource already specified. "There would be no way to just go to the auction and say, 'I'll take what's available,'" Kuhn said.

Kevin Murray, attorney for the Coalition of Midwest Transmission Customers, agreed that network customers aren't currently following MISO's Tariff as written but added that if they did, and had to identify resources before participating, the capacity auction would clear at near-zero prices "until the end of time." Plante agreed.

Other stakeholders suggested it was time to re-examine Module B and update its network resource definitions to align with today's emerging technology.

Plante said WEC wasn't "wedded" to its proposal and asked stakeholders for more written feedback on the two types of BTM generation.

"This uppercase and lowercase BTMG personally drives me nuts," said Planning Advisory Committee Chair Cynthia Crane during a Sept. 27 meeting of her committee. She suggested MISO instead use an "R" before the BTMG acronym to differentiate registered and unregistered BTM generation, instead of using the "uppercase" and "lowercase" designations.

MISO will continue to discuss market definitions for BTM generation at the November RASC meeting. Earlier this year, Manager of Resource Adequacy John Harmon said he thinks the energy industry will be focusing on BTM and distributed energy resource issues for years to come.

Entergy Floats MISO External Zone Hedging Plan

By Amanda Durish Cook

CARMEL, Ind. — After months of stakeholder discord surrounding MISO's plan to incorporate external zones into its capacity auction and divvy up excess auction revenues, Entergy last week emerged with its own plan.

The proposal comes a month after the RTO announced it would delay creation of external zones until the 2019/20 planning year and asked stakeholders to come forward with ideas on hedging mechanisms that would distribute excess revenues to external resources. (See MISO Postpones External Zones Until 2019 Auction.)

During an Oct. 11 Resource Adequacy Subcommittee meeting, Entergy's Rachelle Johnson offered a proposal in which market participants would request hedges for supply arrangements with an external resource once a year. To be eligible, those arrangements must be active during the upcoming delivery period, have a term of at least five years and not already be covered by a hedge, Johnson said.

MISO would then perform a feasibility test of requested hedges using auction estimates from its loss-of-load studies, and deny hedges if they exceed estimated funds. If the amount of surplus auction revenue was insufficient to fund all outstanding hedges, then the funding of those hedges would be reduced proportionally.

Market participants would receive hedges for the next five years in the event the resource did not clear in the auction, Johnson said.

WEC Energy Group's Chris Plante asked

Continued on page 13

MISO NEWS

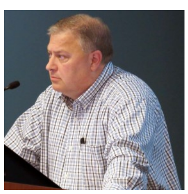
Ameren Calls for Milder MISO Response to Uninstructed Deviations

By Amanda Durish Cook

CARMEL, Ind. — Ameren Missouri is urging MISO to scrap a newly proposed process for identifying when generators deviate from dispatch instructions, asking the RTO to instead take a more lenient approach.

The new process, which relies on a calculation formulated with help from the RTO's Independent Market Monitor, would impose a "failure to follow dispatch" warning when a resource fails to move at least half its offered ramp rate over four consecutive dispatch intervals. Generators are currently flagged after they deviate by more than 8% from dispatch signals over four consecutive intervals. (See *MISO Invites Feedback on Plan to Curb Dispatch Deviations*.)

The utility is asking MISO to instead use an incremental percentage approach consisting of tightening tolerance bands over a period of time — or to delay the project altogether and only focus on generators that deviate from setpoint instructions for an hour straight.



Jeff Moore | © RTO Insider

"We understand the concerns with [day-ahead margin assistance payment] and the concerns about not following setpoint instructions," Ameren Missouri's Jeff Moore said during a presentation given at an Oct. 12 Market Subcommittee meeting. "However, we believe there should be further discussion on the topic to fully understand the goals of this effort, address concerns of generators that are making good faith efforts to follow setpoint, and possibly explore other alternative proposals."

Moore suggested that MISO could decrease its 8% threshold to 7%, and then 6%, to test improvement at each stage. He said his proposal maintains the current practice already familiar to generators. He also added that MISO could drop a new calculation altogether and focus on generators that don't respond to dispatch instructions for at least one hour.

"To us, 60-minute deviations are a bigger problem. They're not making a good faith effort," Moore said.

As it stands, MISO's new calculation could penalize larger units with low ramp rates, he said.

Ramp rates offered by MISO are not always the same over the entire class of generation, Moore said, asking for a "reasonable allowance" for units to respond to setpoint instructions.

"Baseload coal-fired units are not precision instruments," he said. "The system models are what they are, but I sometimes feel we're trying to fit a ramp rate with an imperfect machine."

Moore said large baseload issues can be inundated with "normal" delays: fuel quality issues, feed rates, or problems with valves that can consume ramp rate time and result in a failure to follow dispatch flags.

"These happen when you're stopping and starting large pieces of equipment," Moore said. "Some days it may sit there and hum perfectly, and it may only be 2 to 3 MW short."

Monitor staffer Michael Chiasson pointed out that MISO offers numerous ramp rates for generators to select. "You have 30 different ramp rates to choose from to avoid a homogenous ramp rate," he noted.

"We aren't interested in penalizing generators that make a good faith effort. Perhaps if we have examples of what a good faith effort looks like for this class of generator," Chiasson said, asking large baseload generators to provide scenarios in which normal characteristics of the generator would slow down an otherwise faithful dispatch response. He added that the Monitor isn't "fast and concrete" on its proposal and the calculation could be tweaked a bit, but argued against gentler treatment of large baseload generators.

"When someone offers a ramp rate, they're saying they can move those number of megawatts, and MISO should expect it of them. I don't think we should try and levelize this because, 'It's a coal/steam unit; don't expect much out of it.'… That's not a comparable standard," Chiasson said.

He said it would be unfair to owners of fast-moving gas units to allow coal units a watered-down dispatch grace period.

"We've been recommending this for a half a decade," fellow Monitor staffer Michael Wander reminded stakeholders.

MISO Market Quality Manager Jason Howard said the RTO will issue a more detailed uninstructed deviation proposal in November. He also said the RTO will review Ameren's proposal and stakeholder comments.

Entergy Floats MISO External Zone Hedging Plan

Continued from page 12

whether the proposal intended to align hedging with firm transmission service. Johnson said it could.

Indianapolis Power and Light's Ted Leffler wondered whether external resources with firm transmission service would stop promising capacity to a particular zone, and instead shop for the best zonal resource credit.

"Are you just going to look for the easiest, cheapest place to dump it?" he asked, adding, "Not that that's a bad thing."

Laura Rauch, MISO manager of resource adequacy coordination, said firm deliverability means to deliver load to anywhere within the RTO, not to any particular zone or load.

Plante, who is also RASC chair, asked for more stakeholder proposals on how to provide hedges to external capacity suppliers. "This is why MISO delayed this, to get more stakeholder input on this topic," he reminded stakeholders.

Rauch said MISO will continue to hold discussions on external zones in upcoming meetings up until its planned filing with FERC in early spring. She said MISO would lead more discussion on external zone hedging, in addition to how pseudo-tied resources and fixed resource adequacy plans would interact with external zones and how it will define border resources.

MISO NEWS

DOE 'Resiliency' Must Respect Planning, Research, MISO Says

By Amanda Durish Cook

CARMEL, Ind. — MISO will make two points in its comments to FERC in response to Energy Secretary Rick Perry's proposal to allow "resilient" resources with a 90-day on-site supply of fuel to fully recover their costs. (See Perry Orders FERC Rescue of Nukes, Coal.)


Shawn McFarlane | © RTO Insider

The first point, according to Executive Director of Strategy Shawn McFarlane: The commission's response to the Department of Energy's Notice of Proposed Rulemaking should respect MISO's existing reliability process that incorporates state rules.

The second: Any monetary value placed on resiliency must be supported by research.

"MISO and MISO states have a well-established process to address reliability and resource needs ... and any approach needs to respect those regional processes, and even those regional differences," McFarlane said at an Oct. 11 Resource Adequacy Subcommittee meeting.

He also noted that "MISO supports a thorough and complete process" for detailing reliability and resiliency attributes, and will urge a well-researched approach.

McFarlane said the 21-day public comment period didn't provide enough time to collect stakeholder comments and summarize them in MISO's comments, and he urged stakeholders to make individual filings.

MISO Executive Director of System Operations Renuka Chatterjee echoed McFarlane's comments a day later at an Oct. 12 Market Subcommittee meeting.

"MISO and the states have well-established processes and initiatives in place to protect reliability," she said.

MISO will seek a thorough FERC process and sufficient time for the RTO to review any final rule "so we can judge the applicability while respecting regional differences," Chatterjee said.

"How about the 15-day implementation period?" joked Kevin Murray, attorney for the Coalition of Midwest Transmission Customers, referring to the NOPR provision requiring RTOs to make a compliance filing within 15 days of a proposed rule becoming final (RM18-1).

"I don't know that 15 days would be sufficient, but all jokes aside, MISO will probably ask for more time to review and assess.

> ***"MISO and MISO states have a well-established process to address reliability and resource needs ... and any approach needs to respect those regional processes."***
>
> **Shawn McFarlane, MISO**

Stakeholders that think the 15 days is too short should comment," Chatterjee said.

MISO Independent Market Monitor David Patton confirmed that he would file comments.

"We're going to file comments that stress the importance of being careful and reasonable when picking policies," Patton said. "I don't know that we understand what [resiliency] is unless it's related to reliability."

Patton said he could see the need for resiliency in planning for future contingencies but didn't know if the concept should be monetized.

"Treating it as a separate idea and pursing it outside the market process is very harmful," Patton said.

AEP Seeks $4.8M from MISO in Past Lost Revenues Complaint

By Amanda Durish Cook

American Electric Power has filed a complaint against MISO for failing to collect and distribute millions in transmission charges from three defunct load-serving entities more than a decade ago.

In an Oct. 10 filing with FERC, AEP claimed that MISO owes more than $4.8 million to its PJM transmission affiliates after MISO failed to bill seams-related surcharges to energy providers Nicor Energy, Engage Energy America and The New Power Co., all of which shuttered before December 2004, when MISO created the charges (EL18-7). Nicor folded in 2003 amid financial fraud allegations, while New Power was liquidated in bankruptcy that same year. Engage went out of business in 2004.

AEP is seeking the money through the Seams Elimination Charge/Cost Adjustments/Assignments (SECA), a non-bypassable surcharge in MISO's Tariff intended to recover lost revenues for a 16-month transition period during the elimination of through-and-out rates in late 2004 in the MISO and PJM regions.

AEP said that when MISO was setting up the SECA invoice system, Nicor, Engage and New Power were already defunct and not invoiced, but the RTO nevertheless listed their ensuing charges and "allocated even more SECA charges to the Nicor Energy and Engage sub-zones (based on 2003 data)."

"The allocation of SECA charges to nonexistent LSEs thwarted recovery of the SECA charges, ran counter to fundamental cost allocation principles and resulted in cost subsidies by reducing the SECA responsibility of others," AEP said. "MISO did not bill and collect SECA charges from the three nonexistent LSEs, nor did it adjust the SECA charges allocated to them (as MISO did to others) and, therefore, did not remit to the PJM [transmission owners] the revenue from all allocated SECA charges."

AEP said it asked for compensation from MISO in conference calls in November 2016 and the following August, but the RTO refused to pay. The company asked FERC to either order MISO to pay the charges with interest or set up settlement proceedings to resolve the dispute.

Alliance for Clean Energy New York Fall Conference

Project Execution the Focus for Meeting NY Renewable Goals

By Michael Kuser

| © RTO Insider

ALBANY, N.Y. — Now that New York has done most of the hard policymaking, it's time to focus on building individual renewable energy projects, speakers said Thursday at the Alliance for Clean Energy New York's 11th Fall Conference.

"It is a great time to be a New Yorker advocating for clean energy policies in New York, but all these great, strong leading policies have not put us on an easy glide path to 50%" renewable energy, ACE NY Director **Anne Reynolds** said.

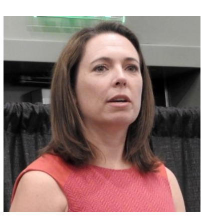
With a tradition of home rule and spirited opposition to large-scale projects, New York is a tough place for building, she said. Thus, ACE NY needs to focus on getting projects built, Reynolds said.

"Without this new focus, and without individual projects succeeding, our collective progress will be on paper only," she said.

She also spoke of the Trump administration's efforts to reverse its predecessor's responses to climate change.

"It's been a year in which I've been glad to focus on advocacy in Albany rather than in Washington, D.C.," Reynolds said. "It's also been a year when I've been happy to be living in Upstate New York, as we watched with hopes and prayers as Americans in Houston and Florida and Puerto Rico and in the Virgin Islands had a front row seat to a changed and changing climate — a dangerous and deadly front row seat."

Ambitious Goals



"New York really has set forth an extraordinarily ambitious agenda for climate policy and clean energy in the state," said **Alicia Barton**, CEO of the New York State Energy and Research Development Authority, who spoke of the state's "extraordinarily ambitious" clean energy goals: 50% renewable energy by 2030, while reducing buildings' energy and electricity consumption by 23% from 2012 levels. It also has committed to build 2,400 MW of offshore wind in the same time frame. (See *New York Seeks to Lead US in Offshore Wind*.)

Meeting its goals will require scaling energy efficiency to deliver outcomes at a lower cost, she said. That's why NYSERDA is making new investments in energy efficiency that are premised on different models than used before under the $10 billion, five-year Clean Energy Fund.

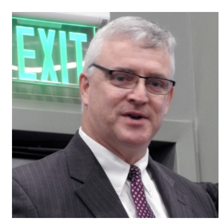
"For example, we're working to launch later this fall a program that we're very excited about called Retrofit New York, which is a $40 million initiative to enable new models to deliver deep energy retrofits in the multifamily housing space, which is an incredibly important segment of the building stock for New York," Barton said. "Retrofit New York is based on a model that's been deployed successfully in a number of European markets, and it's totally new to the U.S. So again, we are asking for partnership from industry, from players in the design of energy-efficiency delivery and project finance."

NYSERDA is also looking at a pilot around pay-for-performance in energy efficiency, but that's in the "fairly early stages of conception," Barton said.

Largest Procurement in the U.S.?

Government procurement is creating the demand that will allow renewable projects to get financed and built, said Joe Martens, director of the New York Offshore Wind Alliance and former commissioner of the state Department of Environmental Conservation.

"In New York, a developer's current opportunities for long-term contracts arise from NYSERDA and the New York Power Authority and, to a lesser extent, the Long Island Power Authority," Martens said. "As you know, there are many open solicitations from both NYPA and NYSERDA for an unprecedented 2.5 million MWh. This procurement, the very first under the Clean Energy Standard policy, is the largest single procurement that New York has ever conducted and, as far as I know, the largest in the United States." (See *NY Clean Energy Commitment Spurs Procurement*.)



Rich Allen, NYPA's vice president for project and business development, said he was excited to tell the conference about the agency's procurement until he realized that — with a request for proposals open and client confidentially applying — he was not free to discuss many of the details. The authority was pleased to receive more than 100 proposals offering all the technologies sought, Allen said.

"Our procurement goal when we pulled together this RFP was to hit three bullet areas: The Clean Energy Standard; we also wanted to meet our customers' renewable

Continued on page 16

Alliance for Clean Energy New York Fall Conference

Project Execution the Focus for Meeting NY Renewable Goals

Continued from page 15

goals; and we're also seeking lower-cost renewable energy," Allen said. "The CES will require about 29 TWh of renewable energy statewide by 2030. NYPA's share is about 4 TWh, 1 TWh of which it is seeking in the current RFP."

All NYPA projects — either wind, solar, hydro or biomass — will be required to be in service by 2022, with a minimum size of 10 to 20 MW, depending on the technology.

The most innovative aspect of the RFP is NYPA's use of a prepaid power purchase agreement, in which the agency would serve as matchmakers between generators and loads. NYPA can only procure as much renewable energy as its customers express an interest in.

Retirement Issues

Doreen Harris, NYSERDA director for large-scale renewables, said that one new aspect of the CES procurement is the setting of minimum quantity requirements. "So for this year, our minimum procurement target is about 1.3 TWh, and should in November we not obtain that quantity, we would issue a second solicitation in 2017," Harris said. "And this will continue ... and will set the stage for what will be a really significant pipeline of projects both under development and in construction in the state."

On Oct. 2, NYSERDA requested that the federal Bureau of Ocean Energy Management consider areas the state felt were best suited for offshore wind development. The selection process "really is the balance of all the uses of the ocean, including fishing, environmental questions and concerns, as well as cables and pipelines," she said.

Asa Hopkins of Synapse Energy Economics addressed the fact that some older renewable generators won't qualify for long-term contracts under Tier II rules. To be eligible, run-of-river hydroelectric facilities of 5 MW or less, wind turbines and direct combustion biomass facilities must have entered commercial operation and had their output included in the state's baseline of renewable resources by Jan. 1, 2003. Under CES guidelines, they also must demonstrate that the renewable energy attributes of these resources are at financial risk.

"The existing independent New York resources are about 20% of the baseline or about 13% of the resources needed to get to the 2030 goal," Hopkins said. If these resources were lost, either by shutting down or by selling their environmental attributes and their energy to other jurisdictions, that could be a significant challenge for New York, he said.

"Opportunities for these resources to export their attributes are increasing," Hopkins said. "Low market prices increase the risk of retirement. Just to reiterate, New York can only claim those resources for its goals if those attributes actually stay in New York. ... Our estimate is that replacing these resources, if they are lost, with Tier I resources would cost New York ratepayers $1.1 billion, and our analysis indicates that there are other policy options that would retain some or all of these resources in New York for less than that."

On an energy basis, these resources "are 47% hydro, 39% wind and the rest landfill gas, biomass and a little bit of solar," Hopkins said. He added that in 2014, New York resources used for renewable portfolio standard compliance in Massachusetts were about 1 TWh, with about one-tenth of that amount used in Connecticut.

"These are fungible resources and they could be attracted back to New York depending on New York's policy," Hopkins said.

Continued on page 17

Alliance for Clean Energy New York Fall Conference

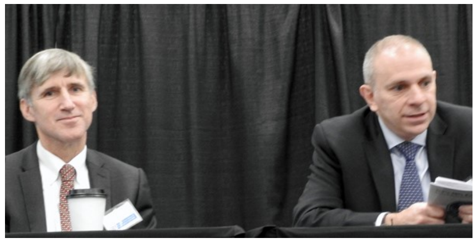
Project Execution the Focus for Meeting NY Renewable Goals

Continued from page 16

Efficiency Puzzle

New York's position as a leader in energy efficiency is falling, said Karl Rábago, director of the Pace Energy and Climate Center. Lime Energy CEO Adam Procell said the reason is that "30% of those electrons, or kilowatt-hours, are wasted in our buildings."

Procell recommended New York regulators avoid being like Florida. "In Florida they love to trumpet their 10-cent energy rate," he said. "They've kept the rates very low; that's what regulators do in Florida. But when you're paying 10 cents/kWh to run electricity through 20-year-old equipment and fluorescent lighting fixtures that we took out in Mass. 15 years ago, that's a very expensive energy bill. Customers care about their bills, not their rates."



Steve Wemple, Con Edison (left), and Adam Procell, LIME Energy | © *RTO Insider*

It's not a good idea to force yourself into playing catch-up on ambitious clean energy goals, said Steve Wemple, director of Consolidated Edison's Utility of the Future Team.

Con Ed has four different incentives or earnings adjustment mechanisms under the state's Reforming the Energy Vision. Some are tied specifically to megawatt-hour reductions, as well as peak megawatts, the traditional programmatic incentives for utilities. The company has two new outcome-based incentives that measure the energy intensity of customers and the adoption of distributed energy resources. Con Ed is also developing a carbon intensity metric that it hopes to use as an incentive mechanism in 2019.

To elicit behavioral change, the company is changing its approach to the market. "We used to have rebate forms, but now it's point-of-sale," Wemple said. "We're trying to work upstream to make sure vendors are stocking the more efficient appliances and making it easier for customers to realize those incentives."

Con Ed is also trying to work through the school system. "Getting school kids to guilt their parents is a very effective tool, and it will pay off down the road," Wemple said. "Hopefully those students will stay in New York state, and we won't have the leakage into Massachusetts."

Procell had the last word: "If New York backslides from 2018 to 2020, we won't make it to our 2030 goals."

Business Issues Committee Briefs

Sharp Year-on-Year Gains for Natural Gas

RENSSELAER, N.Y. — NYISO year-to-date monthly energy prices averaged $35.34/MWh in September, a 3% increase from a year earlier, Michael DeSocio, senior manager for market design, said Wednesday in presenting the ISO's market operations report to the Business Issues Committee.

Locational-based marginal prices (LBMPs) averaged $29.57/MWh for the month, down 3.3% from August and 4.3% from September 2016.

The ISO's average daily sendout was 437 GWh/day in September, down from 477 GWh/day in August and 458 GWh/day a year earlier.

New York natural gas prices gained 5% in September, averaging $2.27/MMBtu at the Transco Z6 hub. Prices were up 72.2% from a year ago. Distillate prices gained 32.3% year-on-year, with Jet Kerosene Gulf Coast averaging $13.40/MMBtu, up from MMBtu in August. Ultra-Low Sulfur No. 2 Diesel NY Harbor averaged $12.80/MMBtu, compared with $11.65/MMBtu in August.

The ISO's local reliability share was 16 cents/MWh, one-third higher than the previous month, while the statewide share "is trending lower at -50 cents/MWh," compared with -31 cents/MWh in August, DeSocio said. Total uplift costs were lower than in August.

In speaking about the Broader Regional Markets report, DeSocio only highlighted that FERC last month accepted NYISO's proposed Tariff revisions regarding cost recovery for the Ramapo PARs, as filed by the ISO in June. NYISO foresees negotiating with PJM by year-end the cost sharing for the replacement of PAR 3500.

Proposed Tariff Changes for Energy Storage

The committee approved proposed Tariff and Ancillary Services Manual changes to define the role of inverter-based energy storage in providing synchronized reserves.

Daniel F. Noriega, NYISO associate market design specialist, presented the BIC-proposed Tariff changes that would allow generators and demand-side resources that use inverter-based energy storage technology to provide spinning reserves.

The ISO last year asked the Northeast Power Coordinating Council (NPCC) to clarify whether such resources can provide synchronized reserves. The NPCC responded that "a storage resource with inverter technology complies with the original intent of the synchronized reserve requirement and therefore shall qualify towards a [balancing authority's] complement of synchronized reserves."

NYISO in January presented its Market Issues Working Group with proposed Ancillary Services Manual revisions to reflect that clarification. Stakeholders provided feedback on the wording, which NYISO incorporated in the updated proposal presented Wednesday. NYISO intends to bring the proposed Tariff and manual changes to the Operating and Management committees for action this month.

Fuel Cost Adjustment Calculation to be Refined

The BIC also approved a proposal that would more closely align the real-time and day-ahead impact tests and penalty calculations used to identify generator misuse of fuel cost adjustments (FCAs). The current day-ahead process is considered more precise because it tests the impact on real-time LBMPs based on market reruns.

NYISO Mitigation Reference Analyst Nicholas Shelton explained that FCAs allow generators to submit a fuel type or fuel price — or a combination of both — along with their energy offers. Once the ISO validates the FCA is within posted thresholds, a generator can update its incremental energy and minimum generation reference levels to reflect the new information. The ISO's Market Mitigation & Analysis unit reviews all FCAs, and those that fail the conduct and impact tests may be subject to penalty.

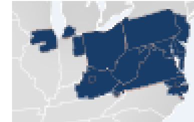
The ISO has found that reviewing FCAs from only the prior seven days does not ensure enough data are available to draw conclusions about tendencies toward an upward bias in prices. The proposed changes would combine the day-ahead and real-time market penalties into one section and lengthen the FCA review period to 90 days from the previous seven days.

According to the proposal, the 10% threshold used in screening for bias has become increasingly restrictive with the decline in natural gas prices, so that a $2/MMBtu price translates into a very tight threshold. Rather than using a 10% threshold to identify bias, the proposal would rely on the greater of 10% or 50 cents/MMBtu.

The proposed changes will go to the Management Committee in October and, if approved, be submitted to the Board of Directors in November prior to filing with FERC.

— Michael Kuser

PJM News



State Regulators Unhappy with PJM Capacity Discussions

By Rory D. Sweeney and Rich Heidorn Jr.

State regulators warned PJM last week that it should avoid any capacity market changes that would increase costs or restrict state policies setting generation preferences.

In a letter Oct. 9, the Organization of PJM States Inc. said it has "increasing concerns" with the discussions in the RTO's Capacity Construct/Public Policy Senior Task Force (CCPPSTF).

OPSI President John Rosales, a member of the Illinois Commerce Commission, said some proposals being discussed by the task force could raise prices significantly and "result in unjustified restrictions of lawful state public policies regarding preferences for characteristics and attributes of electricity supply resources."

PJM stakeholders approved the task force in January following months of debate. The group's issue charge called for a "proactive" review of the Reliability Pricing Model to ensure stakeholders are involved in the RTO's response to "unforeseen events" such as proposed power purchase agreements for coal plants in Ohio and the adoption of zero-emission credits for nuclear plants in Illinois that are at risk of closing because of low market prices. "The failure to successfully anticipate these occurrences resulted in important policy debates circumventing the PJM stakeholder process and going directly to litigation at FERC," it said. (See *PJM to Review Impact of State Public Policies on RPM*.)

'Hypothetical Fears'

Rosales' letter contrasted the task force's charge to identify "areas where state actions and the current RPM capacity construct may not be aligned" with the Capacity Performance rules enacted after the 2014 polar vortex resulted in the loss of 22% of the RTO's generation. "Unlike PJM's initiative to implement the Capacity Performance proposal, there has been no demonstration of facts, data or information other than hypothetical fears supporting the concerns" of the task force, he said.

"Some of the proposals would revise the procedures for resource eligibility to participate in the Base Residual Auction (BRA) and the implementation of the RPM to administratively adjust resource offers and raise the price for capacity. Based on estimations provided in the CCPPSTF, it appears customers are at significant risk of increased cost for capacity. … Regardless of intention, neither artificially and unnecessarily higher capacity costs nor improper restrictions on state public policies would be acceptable to OPSI."

The group criticized the task force's charter, saying that barring discussions of impacts outside of the capacity market "will almost certainly raise the potential for distortions in total supply costs paid by customers."

The regulators also criticized the task force's "accelerated timeline," saying it increases the risk of implementing rules before they are fully vetted and ignores the backlog FERC is attempting to eliminate following its six months without a quorum.

Failing to consider "the intended, and unintended, consequences" of the task force proposals "will likely produce overly narrow, inefficient and excessively costly results," OPSI said.

"OPSI does not believe PJM has demonstrated any convincing reason to interfere with the lawful pursuit of state public policy

Continued on page 20

PJM Drops MOPR in Capacity Talks; Dayton Withdraws

By Rory D. Sweeney

VALLEY FORGE, Pa. — PJM on Monday announced revisions to its capacity proposal while Dayton Power and Light said it was withdrawing its plan.

PJM told the Capacity Construct/Public Policy Senior Task Force (CCPPSTF) that it would eliminate the minimum offer price rule (MOPR) and include all units to which it currently applies in its new repricing structure.

"We would apply repricing as opposed to a MOPR approach," said Stu Bresler, PJM's senior vice president for operations and markets. He said existing MOPR exemptions would continue.

Bresler also announced two other changes to its proposal.

Any offers that trigger repricing would have their offer adjusted to the avoidable cost rate (ACR). PJM would maintain a table of default ACR values by resource class and location, but resource owners could submit unit-specific ACRs if preferred. "We heard loud and clear through the poll results that net CONE [cost of new entry] times B [as the adjusted offer] was not a popular approach," Bresler said.

In addition, states' option to direct PJM to pay adjusted resources less than restated capacity prices was removed. In the revised proposal, every cleared resource will receive the restated clearing price.

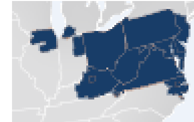
The number of proposals before the task force dropped by one when John Horstmann of Dayton Power and Light retracted his "capacity choice" proposal. That leaves eight options before the task force; Old Dominion Electric Cooperative had removed its repricing proposal from consideration in September.

There was no mention at the meeting of the Organization of PJM States Inc.'s Oct. 9 letter warning the PJM Board of Managers away from task proposals that OPSI said could raise prices significantly and restrict state public policies.

But several proposers made revisions that appear to be keeping OPSI's concerns in mind. American Municipal Power and LS Power updated their definitions for an "actionable" subsidy that expand upon the Independent Market Monitor's definition for its extended MOPR proposal. The definitions identify exclusions for government-sponsored or -mandated procurement. The LS proposal specifically excludes renewables development and demand response programs.

The Monitor likewise added two exemptions to its MOPR proposal for public power and renewable portfolio standards.

PJM News



State Regulators Unhappy with PJM Capacity Discussions

Continued from page 19

in the OPSI jurisdictions. Nevertheless, if PJM persists in proceeding, OPSI would urge PJM to revise its CCPPSTF timeline and process to allow for more robust, comprehensive and appropriate" discussions.

No Mention at Task Force Meeting

PJM spokesman Ray Dotter declined to comment on the letter, saying the response would come from the Board of Managers.

The letter was not mentioned at Monday's task force meeting, although several proposers made revisions that appear to reflect OPSI's concerns.

Among those making changes was American Municipal Power; it was AMP's Ed Tatum who led the fight to create the task force.

"OPSI issues letters after careful consideration and consensus building. This is an important constituency within PJM that does not weigh in on every issue," Tatum said in an email. "As such, when OPSI speaks, I think it's very important for everyone to listen. AMP agrees more time is needed to discuss this issue in the stakeholder process, and that a PJM rush to filing another significant change, especially in light of the [Department of Energy's Notice of Proposed Rulemaking], would not be helpful."

Stu Bresler, PJM's senior vice president for operations and markets, did address a question from Delaware Public Service Commission staffer John Farber about the RTO's expected schedule for implementing revisions.

Bresler said the timeline remains the same: to file by year-end, in time to implement before the next May's Base Residual Auction.

DOE NOPR

Ruth Anne Price, of the Delaware Office of the Public Advocate, asked how DOE's proposal to give price supports to some coal and nuclear generators would interact with PJM's current market structure. (See Perry Defends Call for Coal, Nuclear Supports.)

Bresler said the impact of the NOPR is unknown. If FERC approves the plan without revision, he said, "we've got bigger problems than capacity repricing. I just don't know what alternative they'd take to that."

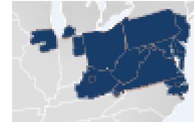
Susan Bruce, who represents the PJM Industrial Customer Coalition, also voiced concern about tweaking PJM's capacity rules too much before the impact of the NOPR is known.

"The ground is shaking in ways that we can't really anticipate what the world is going to look like before the next [BRA]," she said. "The preference would be to exercise some caution since we don't know what the world will look like."

Bresler also attempted to allay fears that PJM will file its plan with FERC if stakeholder preference remains split.

"We're not going to fall on our sword for the PJM proposal, because they all have their pluses and minuses," he said. "To the extent that we can work offline toward something that is more consensus-based, we're all for that."

PJM News



PJM Stakeholders Battle over Cost Cap Rules

By Rory D. Sweeney

VALLEY FORGE, Pa. — Only a few PJM stakeholders attended last week's special Planning Commission session on cost-containment provisions in bids on transmission projects, but they came prepared to defend their opposing positions.

PJM's Sue Glatz reviewed proposed changes to Manual 14F to incorporate cost-containment principles that were identified by stakeholders in previous meetings of the group, including submission requirements, what submission information will be kept private and evaluation guidelines.

Much of the debate at the Oct. 9 meeting occurred over what should or should not be specifically stated in the manual.

Sharon Segner, with merchant transmission developer LS Power, disputed PJM's plan to require bidders to explain the rationale behind requested exclusions from the proposal's cost cap. The decision could be for competitive reasons that don't aid PJM's analysis but might harm the bidder, she said.

Jodi Moskowitz of Public Service Electric and Gas supported PJM's plan to require the supporting rationale for exclusions. She questioned why the requirement was a concern given that supporting information should be treated on a confidential basis.

"Isn't a lot of this information redacted?" she asked.

Segner requested that the manual language guarantee the confidentiality of bidders' explanations for any exceptions to their proposed cost cap, such as if the prices for certain materials change drastically or the anticipated siting route fails to receive approval.

"If you're asking for supporting rationale [to be included within proposals], it should be made clear in the business practice language that that rationale will not be made public," she said.

Glatz said she would investigate what changes might better protect "commercially sensitive language."

Creating Clarity

Stakeholders disagreed on whether to enunciate that PJM will not consider any cost-cap guarantees beyond those related to construction costs, although they "may be included in the project proposals," and that winning bidders are free to "propose, through the FERC ratemaking process, other cost-cap mechanisms associated with the project."

Segner and Greg Poulos, the executive director of the Consumer Advocates of the PJM States, agreed that the language improves clarity, even if they didn't agree with the policy itself. However, PSEG's Vilna Gaston and Delaware Public Service Commission staffer John Farber opposed it because they felt it suggests powers that go beyond PJM's actual authority.

"I think the FERC ratemaking process speaks for itself," Farber said. "The PJM approval process should not be involved with those ratemaking issues."

"You have no authority to say what someone can file or not file at FERC [or] what FERC can consider," Moskowitz said.

Poulos and Segner agreed that their preference would be for "more opportunity for cost caps in other areas," but that the language demarcates exactly what is PJM's policy.

"I think this is a very helpful sentence because it creates clarity," Poulos said. "It's very clear what PJM is considering and not considering."

"Part of the reason that this whole stakeholder process is going on is because varying types of cost containment proposals are being proposed," Segner said. "I don't think it's obvious that other forms of cost containment won't be considered unless it's spelled out."

"I think what I'm hearing is that people do like the clarity but don't want something that creates the illusion" that PJM has authority to control what can be filed at FERC, Glatz said, attempting to summarize the proceeding.

'Over the Top'

Gaston and Segner again clashed on whether to include requirements that any confidential information that is inadvertently disclosed could not be used in the future by any third parties for any purposes.

"I think that's over the top," Segner said in opposing the requirement, suggesting its intended purpose was to muzzle state regula-

Continued on page 22

PJM News

Operating Committee Briefs

DASR Requirement Drops Again

VALLEY FORGE, Pa. — The preliminary day-ahead scheduling reserve (DASR) requirement for 2018 is 5.29%, PJM's Tom Hauske told the Operating Committee last week. The requirement is calculated for each season by combining the average of the seasonal load-forecast errors and the forced-outage rate, both of which dropped about 0.1% for the 2018 calculation.

The final value won't be known until the data from this month are included, Hauske said. PJM staff will return next month to seek endorsement of the requirement, which is down from this year, when it was 5.48%.

Grid Operator Communications Changes Spark Debate

PJM's Chris Pilong announced proposed Manual 13 changes that would update the DASR requirement and ease the requirements for calling hot weather alerts in the spring and fall.

The changes would allow such alerts at temperatures below the current 90-degree trigger during the spring and fall months when generation and transmission outages lower available capacity.

American Electric Power's Brock Ondayko expressed concern with the change.

"I understand what you're trying to do, but I have a concern about some of the ramifications by kind of making more liberal the circumstances that you would go into a hot weather alert," he said.

"One of the challenges we wrestled with is we have a 90-degree trigger, and is there some other trigger — some other temperature — that makes sense? Unfortunately, there really isn't," Pilong said in response.

He noted days in September or October where the temperature nears 90 degrees and said there's not a lot of historic data for "those unusual temperatures for that time of year."


Dave Souder, PJM | © *RTO Insider*

Ondayko disagreed with PJM's perspective. "I think there are other ways that you could suggest that people have some reserve ready," he said.

The manual changes also would delete redundant information and clarify the emergency procedures that trigger a performance assessment hour under the Capacity Performance rules.

Resilience in Operations

PJM's Dave Souder, Brian Fitzpatrick and Marilyn Jayachandran explained how staff plan to incorporate the RTO's focus on resilience into operations. Many of them deal with increased gas-electric coordination.

"We're going to see more and more gas" generation, Souder said.

Fitzpatrick said PJM is analyzing the pipeline systems serving gas-fired units to identify critical infrastructure, understand where redundancies and limitations exist and "make sure there is enough gas scheduled to meet the requirements."

Jayachandran explained PJM's seasonal, monthly and ad hoc assessments of the system. PJM has developed procedures to factor pipeline issues into its operations.

"We would coordinate with generation owners and pipelines to come up with a plan to determine if the [unit] is able to swap to their dual-fuel" source or another pipeline.

Going forward, PJM will be continuing its gas-electric coordination and working with the Argonne National Laboratory on modeling the pipeline system.

— Rory D. Sweeney

PJM Stakeholders Battle over Cost Cap Rules

Continued from page 21

tors and consumer advocates.

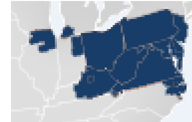
"It's not really about protecting the bidders against each other," she said. "The issue is how it could be used against you later in a litigation proceeding, and you're trying to put language in that would exclude that type of information in a litigated proceeding."

"That's not the intent," Gaston said. "There's confidential information that may be competitive information."

Glatz said she'd ask PJM's attorneys "how complicated that is" to include.

PJM hopes to receive endorsement for the rule changes in time for the upcoming planning year, which would mean bringing it to the Planning Committee for a vote in December at the earliest. Stakeholders asked for another meeting or video conference before then to finalize their requests. Glatz said she would search for an available date prior to the November committee meeting.

PJM NEWS



MIC Briefs

Uplift Solution to be Filed

VALLEY FORGE, Pa. — PJM's plan for addressing uplift remains on schedule, and the final two phases of its three-phase solution will be filed by the end of this week, staff announced at Wednesday's Market Implementation Committee meeting.

The two remaining phases will be filed separately. In May, after four years of debate, stakeholders endorsed the final phase of the plan despite opposition from financial marketers. The filings address allocation of uplift and limit the locations where financial traders can place bids. (See *PJM MRC OKs Uplift Solution over Financial Marketers' Opposition*.)

Bruce Bleiweis of DC Energy asked if PJM had any indication whether newly installed FERC Commissioner Robert Powelson would recuse himself from the decision. Powelson previously chaired Pennsylvania's Public Utility Commission. PJM staff said they had no information on that.

Debate Continues on Intraday Offers

The results were mixed for the Independent Market Monitor's proposed revisions to the intraday-offer procedures, which go into effect on Nov. 1.

Stakeholders endorsed a joint proposal from PJM and the Monitor on changes to Manual 11 that would allow reapplication of the three-pivotal-supplier test after offers are updated. However, they declined the Monitor's recommendations on other Manual 11 changes to verification of energy offers and endorsed PJM's plan. (See "PJM, IMM Agreement on Intra-Day Offers Seen as 'Massive Change,'" *PJM Market Implementation Committee Briefs: Sept. 13, 2017*.)

The Monitor's Catherine Tyler argued that PJM's proposed energy-offer screen, which is being implemented to comply with FERC Order 831, fails to incorporate information from fuel-cost policies and other cost inputs. The offer-verification changes for demand response also don't follow the rules already in place for generators, she said.

"I think there's a real concern that if there aren't more details in the manual, if there's no [offer] cap, then an astronomically high offer could go through, and PJM has no process to stop payment without going to FERC."

The Monitor, she said, is concerned that the process is not standardized. However, stakeholders hesitated to apply a standard before seeing how the process works in the real world.

"I think we have a learning curve, and while I don't disagree with the value of a standard, I would suggest that having a standard without any history isn't productive," CPower's Bruce Campbell said.

PJM's proposal on verifying offers passed with one vote in opposition and 21 abstentions.

Give Them Some Credit

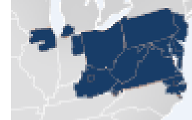
PJM is proposing to use modeling to improve its financial transmission right credit requirements. By incorporating the RTO's PROMOD planning simulations, credit requirements can take into consideration the impacts of future transmission upgrades, PJM's Hal Loomis said. Because system upgrades reduce congestion, they also decrease the value of nearby prevailing-flow FTRs.

The plan would analyze the impact of upgrades on FTR bid and cleared credit requirements. PJM's threshold for analysis would be upgrades with at least a 10% impact on constraints with at least $5 million in congestion. Just three of the 22 system upgrades placed in service for 2017/18 fit those criteria.

PJM is proposing two implementation alternatives. The first, which staff prefer, would incorporate the PROMOD simulation results into the publicly available FTR credit calculator prior to the FTR bid window. While the RTO would only publish the difference between the simulation and historical values for each node, Loomis noted that some stakeholders have complained it would provide market intelligence.

Continued on page 24

PJM NEWS



MIC Briefs

Continued from page 23

"We know transparency is important to our members. It's also important to FERC," Loomis said.

The second option, which resembles the current undiversified adder process, would have PJM issue incremental collateral calls between the close of each FTR bid window and publication of the cleared auction results. While this doesn't give away information, it could require posting additional collateral within a day. Those who miss the deadline would have their bids removed.

PJM hopes to implement one of the processes in time for the 2018/19 annual FTR auction next spring and apply it to all existing positions. Members with a credit shortfall will be restricted in their FTR transactions during a 12-month "transitional cure period" in which they won't be at risk of default but can only make transactions that reduce their credit exposure. No collateral returns will be allowed until the shortfall is cured.

"If there's a shortfall, we want members to cover the shortfall," Loomis said.

A poll in PJM's Credit Subcommittee found strong support for all facets of the proposal, including the RTO's preference for posting the nodal differences, Loomis said.

DC Energy's Bleiweis suggested better alternatives are available, adding that "PJM should keep its views of the future confidential."

Instead, he said, the PROMOD data should be supplemented with third-party forecasts.

"One of the issues we had with the poll is we weren't able to answer the questions we wanted to answer," he said. "There are experts out there who do congestion forecasting. PJM should work with them."

He made the argument during a presentation on his company's concern that the rule changes would still allow participants to hold substantial FTR portfolios while posting little or no collateral. DC recommends a minimum collateral threshold, along with scaling capitalization requirements for increasingly risky positions. Bleiweis also recommended a mark-to-market test in which PJM would collect additional collateral based on the current market value of the purchaser's FTR portfolio.

He acknowledged that these recommendations would "absolutely" increase DC Energy's credit requirements.

"We think it's critical to protect the market," he said. "The worst thing that can happen to the FTR market is another default. We had one in 2008."

PJM Chief Financial Officer Suzanne Daugherty asked stakeholders to address the issue sequentially rather than with an omnibus solution. "We'd like to get this one known exposure addressed," she said.

Bleiweis acknowledged PJM's progress on the issue and agreed to take his proposal to the subcommittee in exchange for Daugherty's commitment that it would be addressed soon.

"Over the last 13 years, we've made a lot of progress on credit issues. We're not going to stand in the way," Bleiweis said.

Earlier in the meeting, stakeholders also endorsed proposed changes to credit requirements for regulation resources to allow credits to offset charges daily. The existing process settles credits monthly but charges weekly, which can create a collateral requirement within the month despite the existence of a much-larger outstanding credit. Travis Stewart of Gabel Associates, which identified the issue and advocated for the change, thanked PJM for the effort.

Monitor's FTR Initiative OK'd Despite Stakeholder Reservations

Joe Bowring | © RTO Insider

Stakeholders were uncharacteristically divided on whether to allow discussion of concerns raised by the Monitor on the long-term FTR market but eventually assented to it. Monitor Joe Bowring presented a problem statement and issue charge on FTRs with terms of one or three years, which he said have a very concentrated ownership and don't accurately reflect the prices in corresponding annual FTR auctions. He suggested there was a lack of interest in the product.

"It has become increasingly clear that the three-year FTR product sold in the long-term FTR auction should be eliminated," the Monitor said in its State of the Market report for the first half of 2017.

Bowring and Vitol's Joe Wadsworth sparred over the Monitor's goals and perception of the problem. Wadsworth asked if Bowring's interests were in improving the efficiency and liquidity of long-term market transactions or simply abolishing FTRs. Bowring responded that the question is whether long-term FTRs are helping or hurting the efficiency of markets overall.

"That's not a very clear answer to me. Take that as constructive [criticism]. Take it as nothing more than that," Wadsworth said.

Rather than a lack of interest, there are impediments, like regulatory uncertainty, that make many participants nervous about transacting years in the future on energy products in general, he said. He later added that Vitol supports open dialogue and wouldn't vote against having a discussion.

Marji Philips of Direct Energy said it was interesting that Bowring's proposal was "being picked apart … which tells me that everyone picking it apart is afraid of losing money."

"We don't see any harm" in the discussion, she said.

The measure received 64% approval with a vote of 108-60 and 53 abstentions.

OPSI, PJM at Odds over PRD

State regulators are at odds with PJM over requirements for demand-side resources, including price-responsive demand (PRD) bids.

PJM says PRD bids should be available year-round, the same as generation resources under Capacity Performance rules. But the Organization of PJM States Inc. (OPSI), which speaks for the state regulators, argues they should be allowed to make seasonal contributions.

The dispute came to a head during PJM's presentation of its proposed PRD rule changes to match CP requirements. PJM's Pete Langbein outlined three proposals. The RTO's proposal would extend annual requirements developed for DR to PRD. A second proposal would limit the triggers for assessing CP penalties to just penalty as-

Continued on page 25

PJM NEWS

PC/TEAC Briefs

IRM Results Approved

VALLEY FORGE, Pa. — Stakeholders approved PJM's 2017 installed reserve margin (IRM) calculations at last week's Planning Committee meeting.

The updated calculations reduced the IRM from 16.6% to 15.8% for delivery year 2021/22, thanks to an anticipated fleet-wide equivalent forced outage rate (EFORd) reduction from 6.59% to 5.89%. PJM calculated EFORd — which measures the probability a generator will fail completely or in part when needed — for the existing generation fleet and the fleet expected in future study years. (See "IRM Reductions," *PJM PC/TEAC Briefs: Sept. 14, 2017*.)

PJM also reduced the winter weekly reserve target for each month this winter. December dropped from 24% last year to 23% this year. January's target fell from 30% to 27% and February from 28% to 25%.

Interconnection Study Process to be Rearranged

PJM is planning to revise its evaluation process for new and upgrade transmission service requests to provide early analysis of recommended upgrades and cost estimates. The initial study, which does address the upgrades or cost estimates, would be replaced with a feasibility study, PJM's Ed Franks said. The subsequent system impact and facilities studies would remain the same. (See "Should I Stay or Should I Go? PJM Still Searching for Resolution to Interconnection Queue Issues," *PJM Planning and Tx Expansion Advisory Committees Briefs*.)

"The analysis as it's currently done is just constantly refined as projects drop out of the queue. That's just the nature of the process," Franks said. "We feel that at least giving them something up front high-level is more appropriate than having them wait until the impact study to get something."

Ed Franks, PJM | © *RTO Insider*

Franks said PJM could evaluate and consider combining the feasibility and impact studies if customers preferred that approach. The changes don't apply to requests that enter the queue through available transfer capability calculations.

PJM is planning to request FERC approve an April 1, 2018, implementation, which will require the Markets and Reliability Committee endorse the Tariff changes in December and the changes to Manual 14A in February. Necessary changes for Manual 2 will be developed through the manual's usual en-

Continued on page 26

MIC Briefs

Continued from page 24

sessment intervals. The third, from DR-participant Whisker Labs, would extend the existing PRD rules to the winter, create a summer-only product and allow it to be aggregated with a winter resource for an annual CP resource.

OPSI Executive Director Greg Carmean made a statement developed from a resolution OPSI sent to PJM's Board of Managers on Oct. 9 urging the grid operator to create market mechanisms that enable participation of summer-available demand resources.

Bowring said that if PRD bids are meant to be price responsive, they should be energy resources rather than capacity.

The issue has existed since PJM implemented its CP construct in response to the 2014 polar vortex. CP requires that all resources have year-round availability and includes penalties for those that fail to respond during emergencies.

OBF Changes

PJM's Tim Horger announced that PJM has alerted NYISO that it plans to end the controversial 400-MW operational base flow (OBF) through northern New Jersey on Oct. 31, 2019.

The OBF was created in May in response to Consolidated Edison ending its decades-old agreement with Public Service Electric and Gas to "wheel" 1,000 MW from upstate New York through PSE&G's northern New Jersey territory and into New York City. Amid stakeholder complaints about its necessity, PJM decided to retain 400 MW of that flow as the OBF.

PJM now says it won't need the cushion to manage energy flows in the area once the Bergen-Linden Corridor project is complete. Per the grid operators' joint operating agreement, PJM provided NYISO two years' notice of the change, which NYISO acknowledged.

OVEC Joining

The Ohio Valley Electric Corp. (OVEC) is planning to join PJM. OVEC's Scott Cunningham said the company plans to join PJM as its own transmission zone, despite having no load to service.

OVEC, which is headquartered in Piketon, Ohio, owns 2,200 MW of generation capacity but will have no load after a U.S. Department of Energy contract ends sometime before 2023. The company was created in 1952 to service roughly 2,000 MW of load from a uranium enrichment plant near Piketon operated by the Atomic Energy Commission.

DOE, which took over operation of the plant after the commission was abolished in 1974, ceased operations there in 2001. The department ended the 2,000-MW contract in 2003 but maintains a load that can be 45 MW at its maximum but is generally less than 30 MW. In months with mild weather, it is less than 20 MW, Cunningham said.

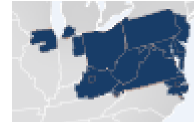
OVEC's two coal-fired generating plants are already pseudo-tied into PJM, and its eight "sponsors" are allowed to sell their portions of the output into PJM's markets. OVEC has no distribution and does not belong to an RTO, although its reliability coordinator function is performed under an agreement with MISO.

The generation would become internal to PJM following membership, eliminating the pseudo-ties, American Electric Power's David Canter said. AEP is one of OVEC's sponsors.

PJM's Asanga Perera said there might be some auction revenue rights associated with the membership.

— Rory D. Sweeney

PJM NEWS



PC/TEAC Briefs

Continued from page 25

dorsement process.

Stakeholders Question Transmission Design Standards

PJM is hoping to continue developing its transmission design standards with new underground line construction guidelines, but transmission customers question their usefulness. (See "Competitive Planning Components Endorsed; Pieces Remain," *PJM Planning & Tx Expansion Advisory Committees Briefs*.)

Transmission developers acknowledge the standards when they sign PJM's designated entity agreement (DEA) to receive approval to construct a project, but the RTO does not enforce them. DEAs are required for companies assigned projects through PJM's competitive-bidding process. Customers were concerned that the standards don't bind the developers to any specific actions.

"It raises the question for me … is whether all underground construction should be held to the same … standard," said Ed Tatum of American Municipal Power.

"PJM is not going to go through a checklist with the proposing entities ensuring that they considered all of … the minimum standards. It's more for an awareness," the RTO's Michael Herman explained. Some of the highly detailed standards are "really beyond the scope of tracking," he said.

"These are minimum standards," PJM's Sue Glatz added. "These are not the only standards that apply to transmission projects." Transmission owners have their own, she said.

Resilience in Planning

As PJM works on factoring resilience into planning, stakeholders are hoping the new criteria will address specific issues. PJM's Mark Sims provided an update on the RTO's progress, which elicited questions from state advocates.

Ruth Ann Price with the Delaware Division of the Public Advocate asked about a comment PJM CEO Andy Ott made at the Grid 20/20 conference in September. Ott had said that one of PJM's resilience goals would be to make "critical facilities less critical." (See *PJM Defends Resilience Focus as Pre-emptive, not Excessive*.)

Price asked how that concept would be applied in PJM's planning, but the RTO's Steve Herling cautioned against jumping to conclusions.

"That's just an example that Andy was using as to how we might visualize the problem and how we might go about solving them," he said.

Greg Poulos, executive director the Consumer Advocates of the PJM States, was disappointed PJM isn't specifically focused on that goal.

"I was really surprised to hear that's not a main emphasis. I didn't realize it was just an example and not a major project," he said.

PJM staff asked for patience in developing a plan.

"Traditional power flows are well understood. They haven't changed much over time, those metrics. But for resilience, we're creating brand new metrics," Sims explained. "I think the approach is to set a longer timeline … but we're still very much working on the technical side of things."

Interconnection Webpage Gets a Facelift

PJM has redesigned its webpage for the interconnection queue to incorporate more information. PJM's Tawnya Luna unveiled the new look, explaining that it includes new county-level and megawatt filters. Users will be able to save a list of projects and receive weekly or monthly updates on them via email.

The site will change over in late October. PJM is seeking feedback for future revisions, Luna said.

How Immediate is Immediate?

Transmission customers and merchant transmission developers joined together at last week's meeting of the Transmission Expansion Advisory Committee to raise concerns about PJM's categorization of "immediate need" projects.

The debate began when Sims described modifications that will raise the costs of a project in Dominion Energy's territory. The b2361 project northeast of Fairfax City, Va., originally ran about 4.5 miles from the Idylwood substation to a new Scott's Run substation and was expected to cost about $32 million. But that plan ran into siting issues at Scott's Run. The project's scope has been expanded to instead rebuild the Tysons substation and run the line there for a total cost of at least $111.7 million. The project's in-service date has also been moved back five years to 2022.

Mark Ringhausen with Old Dominion Electric Cooperative said the changes should warrant including the project in PJM's competitive bidding processes for transmission projects that were developed through FERC Order 1000, but Dominion's Ronnie Bailey disagreed.

"I don't think an Order 1000 process would get us to a better answer," he said.

Sims said the project has already been approved for construction by PJM's Board of Managers.

"We're changing to scope for it," he said.

"This seems a little different than a routine scope change because it's a five-year scope change," said LS Power's Sharon Segner. "Delaying the in-service date by five years would clearly put this project not in 'immediate need.' … We would encourage this immediate-need designation process to not be a rubber stamp process."

PJM's Tariff requires that "immediate need" projects must be in service within three years. But Sims clarified that the designation refers to when the project is needed, not when it will be in service.

John Farber with the Delaware Public Service Commission brought up the issue again later in the meeting during a discussion of projects in Public Service Electric and Gas' territory.

"Really, it's a 'wanted by' date, and the 'required date' is when it actually goes into service?" he asked.

Sims said the "required in-service date" is when the project is needed, but that date can't always be met. He added that it's "a little circular" to suggest competitive bidding for such projects would be faster at defining an in-service date because that wouldn't be known until the end of the bidding process.

— Rory D. Sweeney

SPP NEWS

SPP, Mountain West Integration Work Goes Public

By Tom Kleckner

SPP COO Carl Monroe kicks off a joint meeting between the RTO and Mountain West Transmission Group at SPP headquarters in Little Rock, Ark. | *© RTO Insider*

LITTLE ROCK, Ark. — SPP began the public portion of integrating the Mountain West Transmission Group with a pair of lively stakeholder meetings Friday and Monday.

Representatives from the two entities shared details of SPP's integration process, proposed modifications to the RTO's governing documents and the integration's timeline. The two meetings attracted about 325 current and potential SPP members, state regulators, and environmental and customer advocates in person or on the phone.

"This will start the debate process as we work together in a way that benefits both SPP and Mountain West," SPP COO Carl Monroe said in kicking off the meeting at Mountain West member Tri-State Generation and Transmission's offices in Westminster, Colo.

During a Monday meeting in Little Rock, SPP members peppered representatives with numerous questions about several of Mountain West's proposals to modify the RTO's stakeholder process.

The "Westsiders" have suggested:

- Creating a Westside Transmission Owners Committee with decision-making authority over issues reserved to the transmission owners;
- Prohibiting the SPP Board of Directors from changing decisions by the new committee, and replacing the board's secret ballots with open ballots;
- Expanding the Regional State Committee's authority to include resource adequacy and congestion rights allocation oversight for SPP's Western Interconnection region, and giving Western members of the committee the right to direct SPP to make FERC filings; and
- Adding seats on the board committees for Western representatives.

Kenna Hagan, senior manager of planning, policy and strategy for Black Hills Corp., said Mountain West's proposals result from years of discussion among the coalition's 10 utilities.

"This is a compromise position that's taken us three years to derive," Hagan said. "There's strong interplay between each of those items we're proposing. It's not all or nothing … but it's important to us to move forward as a group."

Duke-American Transmission Co.'s Bob Burner called Mountain West's suggestions "protectionist proposals," saying, "It certainly discourages independent transmission developers from looking at anything on the west side."

Other stakeholders questioned the differences between east and west in transmission cost allocations and rate design, but those involved in the negotiations worked hard to allay concerns.

"These are not meant to be two separate processes," said Tri-State's Mary Ann Zehr. "They're supposed to work in concert with each other."

"You're bringing up things we will have to address [in the stakeholder process] and work through," said SPP Associated General Counsel Mike Riley.

SPP and Mountain West are in the third stage of the RTO's process for integrating new members, when staff will convene special all-member and stakeholder meetings to discuss proposed document changes. Mountain West triggered the stage when it said in September it had completed initial discussions with SPP's management team and would begin public negotiations. (See *Mountain West to Step up Talks with SPP on Joining RTO*.) Mountain West, which primarily services Colorado, Wyoming and Nebraska, announced its intentions in January to join SPP. The two entities are working on an Oct. 1, 2019, target date for membership.

SPP's existing members will see a phased-in, reduced administrative fee. The fee, currently 48 cents/MWh, will drop to 43 cents for 2020, resulting in annual savings to existing members of $16 million to $25 million for the first three years and a total net present value benefit of approximately $209 million for the first 10 years of Mountain West membership, SPP said.

A Brattle Group study conducted for Mountain West found the entity could save $53 million to $71 million annually through 2024 by participating in a day-ahead market and replacing its nine tariffs with one. A separate Glarus Group study of DC tie flows in a combined Mountain West-SPP market showed "significant" benefits, with annual net production cost savings ranging from $11.7 million to $28.8 million.

Any changes to SPP's governing documents will be reviewed by stakeholders on the Corporate Governance Committee (governing documents), Strategic Planning

Continued on page 28

SPP NEWS

FERC Rejects SPP's Request to Remove Day-Ahead Must-Offer

By Tom Kleckner

FERC on Friday rejected SPP's request to remove its day-ahead must-offer requirement, saying the RTO had not provided "sufficient support" for its proposed Tariff revisions (ER17-2312).

"SPP's proposal removes the only direct penalty, beyond referrals to the commission's Office of Enforcement, for physical withholding and associated manipulative behavior in SPP's day-ahead market," the commission said. It also pointed out the RTO didn't suggest additional protections going forward.

"Removing the limited day-ahead must-offer requirement in its entirety would make monitoring and capturing potential physical withholding in the day-ahead market even more important," FERC said.

MMU, Golden Spread Raise Concerns

SPP's Market Monitoring Unit and member Golden Spread Electric Cooperative both supported the proposal, though not without reservations.

The MMU raised concerns about the potential for physical withholding without the requirement and requested the removal on an interim basis for 18 months — allowing the Monitor and SPP to determine whether it does result in increased withholding.

The MMU recommended in its 2014 State of the Market report that SPP remove the limited day-ahead must-offer requirement, establish a phased penalty structure for physical withholding, update the defined thresholds for physical withholding and revise the generator capability thresholds. However, those proposals failed to pass the stakeholder process.

Golden Spread's issues were with the day-ahead market's competitive operation without a must-offer requirement. The co-op said it is "unsound" to rely only on the expectation that the withholding rules will catch improper behavior. The co-op also argued the Tariff should be clear on what constitutes physical withholding, so market participants aren't subject to an "information gap."

Without access to the shift factors and other information SPP collects, market participants have no warning on the impact of their offers, forcing them to make guesses regarding resource demand and market clearing prices, Golden Spread said.

It also said that without the must-offer requirement, market participants may offer into the day-ahead market to avoid failing ambiguous physical withholding tests, rather than basing their decisions on economics.

'Anectodal' Evidence

FERC said SPP referred to "anecdotal" evidence that there is little reason to fear physical withholding but did not "provide further support for this assertion."

The commission said that while SPP assured it that there is ample resource participation in its day-ahead market, "sufficient resource participation is not a safeguard against physical withholding and associated market manipulation." FERC said a generating resource could hold local market power because of a transmission constraint, despite a large market-wide surplus.

"The must-offer requirement is the physical withholding analog to the market power mitigation rules to address economic withholding," the commission said.

SPP filed the request in August, saying the must-offer requirement was no longer needed and that its reliability needs are met "at all times" by the full must-offer requirements for its reliability unit commitment processes and real-time market. The RTO said the MMU's eye on physical withholding in the day-ahead market has a "more significant impact on market participant behavior" and, based on three years of observational data, "robust" participation in the day-ahead market resulted in capacity offered in the day-ahead market "consistently exceeding" reported load by about 50%.

SPP's request was the result of a directive from FERC when it conditionally accepted the RTO's Integrated Marketplace in 2012. The commission asked SPP to revise its Tariff to create a process in which it or the MMU would:

- Verify that market participants had not exceeded a predetermined acceptable load forecasting error; and
- Establish noncompliance penalties if market participants' estimations exceeded the acceptable range of load forecasting error.

SPP, Mountain West Integration Work Goes Public

Continued from page 27

Committee (negotiating strategies, new member deliberations), Markets and Operations Policy Committee (Tariff revisions) and the RSC (state regulatory agency input).

SPP's board will have the final call on any changes.

SPP will conduct a reliability assessment of each incoming member's transmission system to ensure they meet the minimum reliability planning criteria. Staff performed similar assessments when it added Nebraska's utilities and the Integrated System.

"We've been through this before," said Lanny Nickell, SPP vice president of engineering.

Xcel Energy's Joe Taylor gives an overview of the Mountain West system. | © *RTO Insider*

FERC News

FERC Chair: Court Ruling Won't Change Pipeline Reviews

By Rich Heidorn Jr. and Michael Brooks

WASHINGTON — A court ruling requiring FERC to consider the impact of greenhouse gas emissions won't have a "significant" impact on the agency's licensing of natural gas pipelines, Chairman Neil Chatterjee said Friday.

On Aug. 23, the D.C. Circuit Court of Appeals ruled 2-1 that FERC's environmental impact statement (EIS) for the Southeast Market Pipelines Project should have included "reasonable forecasting" of the project's impact on GHG emissions.

FERC had contended that the impact of the pipelines on GHG emissions was unknowable, dependent on variables including the operating decisions of individual plants and regional power demand.

Ruling in a challenge by the Sierra Club, the court said FERC had failed to meet the requirements of the National Environmental Policy Act. FERC "should have either given a quantitative estimate of the downstream greenhouse emissions that will result from burning the natural gas that the pipelines will transport or explained more specifically why it could not have done so," the court ruled. (See *FERC Must Consider GHG Impact of Pipelines, DC Circuit Rules*.)

In a press conference Friday, Chatterjee said he didn't "believe that [the court's ruling] was going to significantly alter the way that we evaluate these projects."

Nexus Order

As an example, he pointed to the commission's Aug. 25 order approving the Nexus Gas Transmission Project, a 255-mile pipeline from Ohio to Michigan (CP16-22) that is being built by DTE Energy and Enbridge's Spectra Energy. The order contained a lengthy discussion of the environmental impacts of the project, arguing that its analysis complied with the National Environmental Policy Act.

The commission also noted that, in the final days of the Obama administration, EPA had requested the removal of a statement from the project's EIS that said that there is no accepted methodology for correlating specific GHG amounts to changes in a region's environment. The agency also asserted that comparing a project's emissions to statewide emissions did not contribute to an analysis on global climate change.

"The EPA provides no compelling reason to change or supplement the final EIS," FERC wrote. "The final EIS specifically notes that comparing project-related GHG emissions to statewide GHG inventories provides a frame of reference for understanding the magnitude of GHG emissions in general, but that it does not indicate significance. … The final EIS appropriately discusses climate change, quantifies project-related GHG emissions, identifies emission reduction and mitigation measures and programs, and notes the projects' consistency with climate goals in the Midwest region."

"In many ways, that approval anticipated the court's argument in the Southeast case and addressed a lot of it," Chatterjee said. He declined to comment on any other projects.

The Sierra Club requested rehearing in the Nexus case, saying the commission's GHG evaluation failed to meet the D.C. Circuit's requirement. "Regardless of what methodology FERC ultimately uses, it cannot ignore the issue by claiming, without support, that there is no way fulfill its duty committed to it by NEPA," Benjamin A. Luckett, senior attorney for Appalachian Mountain Advocates, wrote on the Sierra Club's behalf.

Southeast Markets' Supplemental EIS

On Sept. 27, the commission responded to the court's remand on the Southeast Markets project with a supplemental EIS that included estimated GHG emissions but maintained that the project would have no significant effect on the environment (CP15-16, *et al.*).

The 685-mile project by Duke Energy, NextEra Energy, Spectra Energy Partners and the Williams Companies, is composed of three interconnected pipelines in Alabama, Georgia and Florida: the Hillabee Expansion Project, Sabal Trail and the Florida Southeast Connection.

FERC's supplemental EIS concluded that three Florida natural gas generators that would be supplied by the pipelines — Florida Power & Light's new Okeechobee Clean Energy Center; Duke Energy's new Citrus County combined cycle plant and FPL's existing Martin County Power Plant — would emit as much as 12.5 metric tons of CO_2 annually while retirements of coal, oil and natural gas plants replaced by the new units would eliminate 6.14 tons — a net increase of 6.36 tons.

Burning of the pipeline's uncommitted capacity could add an additional 2 tons, FERC said. The net total of 8.36 tons equals 3.7% of Florida's GHG emissions in 2015, the commission said.

The commission said, however, that it was unable to find a method to "attribute discrete environmental effects" to the emissions. "The atmospheric modeling used by the Intergovernmental Panel on Climate Change, Environmental Protection Agency, National Aeronautics and Space Administration and others is not reasonable for project-level analysis," the commission said.

FERC also said the social cost of carbon tool is not useful for project-level NEPA review because it does not measure the incremental impacts of a project on the environment. The commission also cited a lack of consensus on the appropriate discount rate and "the monetized values that are to be considered significant for NEPA reviews."

A group of Albany, Ga., residents responded to FERC's supplemental filing with a protest, saying "it assumes that coal-burning power plants will be shut down in the future but does not consider the methane output from the many compressor stations that are also planned for these pipelines."

Other Approvals

On Friday, FERC issued certificates approving two other pipeline projects: the Atlantic Coast Pipeline (CP15-554, *et al.*), which will deliver up to 1.5 million Dth/d over 604 miles of new pipelines between Harrison County, W.Va., and eastern Virginia and North Carolina; and the Mountain Valley Pipeline (CP16-10, *et al.*), which will transport up to 2 million Dth/d from Wetzel County, W.Va., to Pittsylvania County, Va.

Commissioner Cheryl LaFleur dissented in the ACP decision

FERC NEWS

Perry Defends Call for Coal, Nuclear Supports

Continued from page 1

or an invitation to "start a conversation."

"The base reason that we asked for this … is that, for years, this has been kicked down the road," Perry said of the NOPR, published in the *Federal Register* last week.

The proposal would require FERC-jurisdictional RTOs and ISOs with capacity markets and day-ahead and real-time energy markets to ensure full cost recovery for any generation that is capable of providing "essential energy and ancillary services" and has a 90-day fuel supply on site "enabling it to operate during an emergency, extreme weather conditions, or a natural or man-made disaster." Units subject to cost-of-service rate regulation would be excluded.

Essential services include voltage support, frequency services, operating reserves and reactive power. Just and reasonable rates for such generators would cover "its fully allocated costs and a fair return on equity," including operating and fuel expenses and the costs of capital and debt, the NOPR said.

Rep. Bobby Rush (D-Ill.), ranking member of the subcommittee, asked how Perry reached the conclusions in the NOPR, given that FERC and NERC have said that the grid is reliable. In an apparent reference to the NOPR, FERC Commissioner Robert Powelson promised in an Oct. 4 speech "not to destroy" the markets, leading Commissioner Cheryl LaFleur to tweet, "Great message!"

"I respect the FERC members' views," Perry said. "I think their picture is one that is a snapshot in time. … What I think one of my roles is is to think outside of the box."

The grid is normally resilient during "blue sky" days, he said, and his support for an "all of the above" generation mix was proven during his time overseeing wind growth as governor of Texas. "But the wind does not always blow. The sun doesn't always shine. The gas pipelines — they can't guarantee every day that that supply is going to be there."

"It seems to me what you're saying is, 'Well my gut feeling has more of a priority … rather than what these experts have said,'" Rush responded.

While no Republican on the subcommittee criticized the proposal — and many offered their support and praise for Perry — party leadership did not tip its hand.

"While I reserve judgment on the policy solutions, the fact that the secretary stepped in to this complicated debate reflects the current need to have a broader conversation about the functioning of the nation's electricity markets," subcommittee Chair Fred Upton (R-Mich.) said in his opening statement.

Rep. Greg Walden (R-Ore.), chair of the full Energy and Commerce Committee, made no mention of the NOPR in his opening remarks, instead focusing on the Department of Energy's budget.

Countering Subsidies

Perry said he was attempting to counter subsidies that have benefited renewables at the expense of coal and nuclear. "There is no such thing as a free market in the energy industry," he said multiple times. "Government's picking winners and losers every day by regulations … and I'm at least honest enough to say it." He pointed to state utility commissions, policies such as renewable portfolio standards, and Texas' own Competitive Retail Energy Zones as evidence.

Rep. Gene Green (D-Texas) pushed back on this, pointing to the retail choice offered in his state and the uncoupling of generators from utilities.

"Gene, you know me, I'm all about that competition," Perry said. "That's what we did … we deregulated that market and that competition came. But the idea is, we had an administration before that had their thumb on the scale. I think you'll agree, [former President Barack Obama] liked green energy, and that's where the subsidization came."

Rep. Paul Tonko (D-N.Y.) pointed out that the production and investment tax credits for solar and wind resources, respectively, were passed by a Republican-controlled Congress.

Not Supported by DOE Study

Rep. Frank Pallone (D-N.J.), ranking member of the full committee, said the NOPR was not supported by the grid study the department released in August. He asked Perry what analyses the department or its national labs had done to support the proposal.

Perry did not respond to the question, instead challenging Pallone's premise. The grid study, he said, didn't address "with specificity the events I'm concerned about," he said, citing the 2014 polar vortex. In fact, the report had about 17 references to "extreme weather" or the polar vortex. (See *Perry Grid Study Seeks to Aid Coal, Nuclear Generation*.)

Perry also sparred with Rep. Michael Doyle (D-Pa.), who said the committee had held eight hearings on markets and reliability. "We've actually been having the conversation you claimed to be starting," he said.

"This has been discussed for a long time, as you rightfully said," Perry conceded. But he said it was now time for action.

Continued on page 31

FERC News

Perry Defends Call for Coal, Nuclear Supports

Continued from page 30

"Our RTO made that adjustment" after the polar vortex, Doyle said, referring to PJM's Capacity Performance rules, which increased the penalties and bonuses for capacity resources during grid emergencies. "We feel pretty confident with our capacity in Pennsylvania."

"'Pretty confident' is not going to get it [done]," Perry shot back.

Tonko asked if Perry considered consumer costs in developing the NOPR.

"What's the cost of freedom?" Perry responded. "What does it cost to build a system that keeps America free? I'm not sure I want to put that straight out onto the free market."

Directive or Conversation?

Perry said the NOPR was intended to "kick-start a national discussion about resiliency and about the reliability of the grid." Noting the vociferous opposition his proposal provoked, he chuckled, "And best I can tell, we were pretty successful in doing that. ... We're having this conversation now that we really haven't had in this country." (See Consumer Advocates Slam Perry NOPR, RTOs, FERC.)

Indeed, at least 50 companies, regulatory agencies and trade groups have intervened or made comments in the docket FERC opened to respond to the NOPR (RM18-1).

Doyle pressed Perry on discrepancies between the NOPR, which repeatedly says FERC "must" act, and the secretary's repeated references to starting a "conversation."

"Is it a directive to FERC to do this or a conversation?" Doyle asked.

"Both," Perry said.

"So, it's a directive then?" Doyle asked.

"My words are what my words are. I don't back off from them," Perry said.

"It can't be both," Doyle protested. "So, which one is it?"

"Well actually it is both. It can be both. We can have a conversation and I think [FERC] must move. I think they must act. We've kicked this can down the road as long as we need to."

Perry seemed to acknowledge multiple times that FERC would not be obligated to follow such a directive. Legal experts have said that Perry has no power to make FERC, an independent agency, provide the relief he is seeking. (See FERC's Independence to be Tested by DOE NOPR.)

Rep. David McKinley (R-W.Va.), who said he was "100% behind" the NOPR, asked if "FERC were to follow through with your missive, don't you think we'd have a better outcome" than what happened during the polar vortex?

"Well I do, but I mean, that's why we're having this conversation here," Perry answered, saying he wanted to hear from both sides of the issue.

Rep. Kathy Castor (D-Fla.) also said the NOPR conflicted with the findings of the grid study and said it would cost consumers and businesses billions. "There is just no rational basis for this new FERC rule that you're trying to move through as quickly as possible," she said.

"If the request ... the NOPR to FERC is what you say it is, [FERC] won't go forward with it," Perry responded.

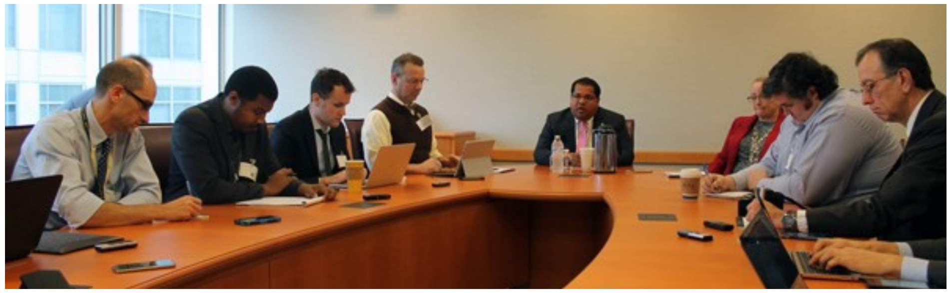
When asked by Doyle if he had considered any better alternatives to the NOPR, Perry answered, "I don't have any idea whether there are any better options. That's one of the reasons we wanted to have this conversation is to bring those up and discuss them.

"I'm not saying that my letter to FERC is the be-all-end-all, but it's obviously been very successful in getting the conversation going."

FERC NEWS

FERC Chair Praises Perry's 'Bold Leadership' on NOPR

Continued from page 1


| © RTO Insider

"I think the bold directive [Perry] took has initiated this conversation, and it's something that we are going to look at very seriously, and I'm confident we'll find a positive resolution to," Chatterjee said in a nearly hour-long press conference at FERC headquarters Friday. "I'm sympathetic to some of the things that Secretary Perry has raised. This idea that there are perhaps attributes that certain generating sources have that have value [and] that are not appropriately being captured by our existing market structure, we need to look at that carefully…

"I also believe strongly in markets. We've invested nearly two decades and billions upon billions of dollars into our existing market structure, and I don't want to do anything to disrupt that market structure," he continued. "Accurately valuing resilience is not a zero-sum game. Compensating baseload generation does not equate to destruction of the markets. On the contrary, I think it's a step toward accurately pricing contributions of all market participants."

Chatterjee said the commission must act within 60 days in response to the Department of Energy's Notice of Proposed Rulemaking, which was published in the *Federal Register* last week.

FERC's Options

The NOPR would require FERC-jurisdictional RTOs and ISOs with capacity markets and day-ahead and real-time energy markets to ensure full cost recovery for any generation that can provide "essential energy and ancillary services" and has a 90-day fuel supply on site. Units subject to cost-of-service rate regulation would be excluded. Just and reasonable rates for such generators would cover "its fully allocated costs and a fair return on equity," including operating and fuel expenses and the costs of capital and debt, the NOPR said.

Chatterjee outlined FERC's options for responding: "We could do an Advance Notice of Proposed Rulemaking; we could do a Notice of Proposed Rulemaking superseding the DOE NOPR; we could issue a final rule; we could do an extension of the comment period and solicitation of further comments; we can convene technical conferences; we can do a notice of inquiry; we could initiate Federal Power Act Section 206 review proceedings."

Asked whether the commission could take an up-or-down vote on the proposal within 60 days, Chatterjee responded, "It could be. We're going to carefully look at it."

Chatterjee said that while he would prefer to delay major actions until the commission is fully staffed with the addition of nominees Kevin McIntyre and Richard Glick, he wouldn't hold up action pending their arrival. The two are awaiting a Senate floor vote after clearing the Senate Energy and Natural Resources Committee on Sept. 19.

"These challenges are too important to wait," Chatterjee said, noting that the

Continued on page 33

FERC NEWS

FERC Chair Praises Perry's 'Bold Leadership' on NOPR

Continued from page 32

commission is planning a "big announcement" on hydropower licensing policy at its next open meeting Oct. 19.

He also defended the commission's refusal to extend the comment period on the NOPR (RM18-1). The commission set an Oct. 23 deadline on comments, with reply comments due Nov. 7. "It's not a new issue," he said. "We have ample time to receive comments."

Kentucky Native on Coal's Role

Chatterjee defended comments he made in a podcast in August, which some FERC watchers interpreted as signaling a break from the commission's traditional "fuel-neutral" policies.

After praising "baseload" coal and nuclear generation for their value to "resilience and reliability," Chatterjee noted that coal provided more than 80% of the electricity in his home state of Kentucky last year. "As a nation, we need to ensure that coal, along with gas and renewables, continue to be part of our diverse fuel mix," he said then.

"I wasn't saying that FERC was not fuel-neutral," he said Friday. "To be clear, whatever solution that we pursue here will be fuel-neutral as well. I agree with Commissioner [Cheryl] LaFleur's assessment that we don't start with a resource and work backwards. We come up with policies that will be applied in a fuel-neutral way."

But he said he agreed with lawmakers who want to preserve "fuel diversity," suggesting coal could act as a hedge against "unintended consequences" from technological changes on the grid.

He cited the switch of the Big Sandy generator in Kentucky from coal to natural gas. Much of the plant's load was from the energy-intensive coal mines in the region.

"So, when the power plant shut down, the coal mines that fed that plant shut down with it. … Now the operators of the gas plant find themselves in a situation where they've got to come to the state for a massive rate increase to account for … lost load," he said. "So that's a perfect example of an unintended consequence that occurs when you have these technological shifts. And I just think we need to be very thoughtful and careful in assessing what the long-term future of our grid looks like when these types of unintended consequences can occur."

Chatterjee declined to offer an opinion on whether a 90-day fuel supply is a valid way to measure reliability. The NOPR said such supplies enable a plant "to operate during an emergency, extreme weather conditions, or a natural or man-made disaster."

"I just think we have to go through our process, take in people's comments. Look at the rationale to see how it would impact them," Chatterjee said. "I'm not prepared at this stage of our process — not having all that complete information submitted — [to say] how we will address that."

The commission also will consider data cited by members of the House Energy Subcommittee during a Thursday hearing with Perry indicating that most outages result from problems on the distribution system rather than from insufficient generation, the chairman said. (See *Perry Defends Call for Coal, Nuclear Supports*.)

"Staff put out an … extensive list of questions to facilitate this kind of dialogue and commenting. I fully expect comments in line with what you're laying out will come in."

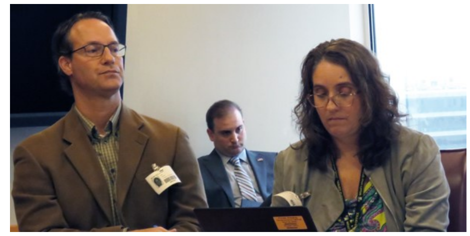
Mum on White House Input on Staff

Chatterjee declined to answer concerns among some FERC watchers that his appointments of General Counsel James Danly and Chief of Staff Anthony Pugliese were directed by the Trump administration.

The commission has traditionally been independent and rarely decides issues on party lines. But some observers said the appointments suggested that could change because the two key positions were filled before the arrival of McIntyre, who was tapped by President Trump to lead the agency. New chairmen typically select their own general counsel and staff chiefs.

Danly, an Iraq War veteran, joined the commission from Skadden, Arps, Slate, Meagher & Flom.

Pugliese, who formerly lobbied on solar, oil and natural gas issues in Pennsylvania, came to FERC after serving as the White House's eyes and ears at the Department of Transportation. Politico described Pugliese in May as one of Trump's "White House-installed chaperones," saying he clashed with Secretary Elaine Chao.



Anthony Pugliese (rear) monitors Chatterjee's press conference as reporters take notes. | © *RTO Insider*

"Day to day, Pugliese and his counterparts inform Cabinet officials of priorities the White House wants them to keep on their radar," *The Washington Post* reported in March. "They oversee the arrival of new political appointees and coordinate with the West Wing on the agency's direction."

At his press conference — which Pugliese and Danly attended — Chatterjee praised the two as "very talented people." The two sat in the rear of the room, behind reporters and facing Chatterjee — Pugliese frequently shaking his head no or yes in response to the questions and answers.

"Mr. Pugliese has extensive experience in infrastructure and public policy, and I've been thoroughly impressed in the manner in which he has comported himself in his time here at the agency," Chatterjee said.

He also praised Danly's "astonishing resume," calling him "one of the most talented brightest, capable energy lawyers in the country."

Were they suggested to Chatterjee by White House officials?

"They were suggested to me by a number of people," Chatterjee responded. "They have sterling reputations, and people who I respect and trust recommended them to me."

Including the White House?

"I'm not going to speak [about] who recommended them," Chatterjee said.

COMPANY BRIEFS

Shell Inks Deal to Buy EV Charging Co. NewMotion

Royal Dutch Shell on Thursday announced plans to purchase NewMotion, a Dutch electric vehicle charging company that owns one of Europe's largest charging networks.

The deal, the value of which Shell didn't disclose, marks the company's first deal in the EV space.

Shell already has a program focused on markets such as Britain, Norway and the Philippines to install fast-chargers at some of its gas stations. That program will continue alongside NewMotion's activities, which focus on home and workplace chargers.

More: *CNET*

CSP Co. eSolar Apparently No Longer in Business

Concentrated solar power company eSolar appears to have ceased operating.

Emails by Greentech Media to key management, including chairman and founder Bill Gross, executive vice president of projects Dale Rogers and vice president of systems engineering Michael Slack, have gone unanswered. The company's website offers a blank page with the message, "Please come back later."

More: *Greentech Media*

Armstrong Coal Plans To Idle Equality Mine

Armstrong Coal expects to idle the Equality surface mine in western Kentucky between Dec. 8 and Dec. 22 because of market overproduction and depressed demand for the high-sulfur coal it produces.

Last year, the mine, which Armstrong has operated since 2010, produced 1.6 million tons of coal, according to the company's website.

More: *The Associated Press*

Entergy Proposes Solar Rooftop Systems for New Orleans

Facing pressure to increase the amount of power it generates from alternative sources, Entergy New Orleans applied to the city Friday to install rooftop solar systems on commercial buildings and connect them to the grid.

The proposal identifies 50 buildings that could work for the project. Some are owned by other companies and one is owned by Entergy. The project would generate 5 MW of power and cost about $14.8 million.

Entergy has pledged to add up to 100 MW of renewable energy resources, amounting to about 10% of its generating capacity.

More: *The New Orleans Advocate*

Google Will Reach 100% Renewable Energy Goal in 2017

After 10 years of being a carbon-neutral company, Google will achieve 100% renewable energy for its global operations this year, according to its updated Environmental Report published last week.

Google says that in addition to reducing its environmental impact, it has created new energy purchasing models that others can follow.

More: *Google*

Report: $2.7 Trillion Needed For EV Infrastructure

The world must spend $2.7 trillion on electric vehicle infrastructure for the vehicles to reach 526 million units by 2040, according to a report last week by Morgan Stanley.

The investment will require a mix of private and public funding across regions and sectors, and automakers or governments with aggressive targets will be at risk without the necessary infrastructure, the report said.

China will make up about a third of global infrastructure spending by 2040, making it the largest EV market.

More: *Bloomberg*

Small Hydrogen Leak Causes Millstone Evacuation

A small hydrogen leak in the Unit 3 turbine building at the Millstone nuclear plant was identified last week, causing the building to be evacuated.

The incident was declared an "unusual event," which is the lowest level of the Nuclear Regulatory Commission's four levels of alert classification.

The leak was resolved about two hours after detection, Dominion Energy Spokesman Ken Holt said.

More: *The Day*

2nd Shareholder Sues over Westar-Great Plains Merger

A second shareholder has sued to stop Westar Energy's proposed $14 billion revised merger of equals with Great Plains Energy.

The suit by Robert L. Reese claims that "deal protection devices" would fend off other potential bidders for Westar, including a right for Great Plains to match any superior proposal.

In September, Westar shareholder David Pill filed a lawsuit alleging the company has not properly disclosed financial projections. Both suits seek class action statues.

More: *Kansas City Business Journal*

DTE Begins Operating Michigan's Largest Solar Park

DTE Energy has begun operating the largest solar park in Michigan.

The Lapeer solar park consists of a 200,000-panel array on more than 250 acres and is one of the largest utility-owned solar parks east of the Mississippi River. DTE began construction on the project in the spring of 2016.

Solar energy makes up 7% of DTE's renewable energy portfolio, with the utility investing $170 million in solar energy since 2008.

More: *DTE Energy*

FEDERAL BRIEFS

IECA Weighs in Against DOE Resiliency NOPR

The Industrial Energy Consumers of America, a trade group representing U.S. manufacturing factories, wrote to the leaders of the Senate's and House of Representatives' energy committees last week, urging them to request that Energy Secretary Rick Perry withdraw his recent Notice of Proposed Rulemaking on grid resiliency pricing.

The NOPR, issued Sept. 28, would have FERC require RTOs to provide "full recovery of costs" for generators with a 90-day on-site fuel supply. IECA said that "though we remain supportive of both coal and nuclear" — the plants most impacted by the rule — "we are opposed to providing subsidies that would damage competitive markets." It also expressed similar sentiments as other groups, arguing that the department's recent study on grid reliability showed there is no threat from early retirements of so-called "baseload" plants. (See *Consumer Advocates Slam Perry NOPR, RTOs, FERC*.)

The group also asked the congressmen to urge FERC to extend the comment period on the proposal to 60 days. A petition by IECA, along with a myriad of other groups, to extend the deadline was denied without explanation by Chairman Neil Chatterjee on Wednesday (RM18-1). Comments are currently due Oct. 23, with reply comments due Nov. 7.

More: *IECA*

IER Speaks out Against DOE Resiliency NOPR

The Institute for Energy Research — a D.C.-based think tank whose political arm endorsed President Trump in the 2016 election — has come out against Energy Secretary Rick Perry's Notice of Proposed Rulemaking on grid resiliency pricing.

"Like using a sledgehammer to swat a fly, this rule would end up causing enormous destruction even if it also managed to provide more resilient baseload capacity," IER's Director of Policy Kenny Stein wrote Wednesday.

Last July, the think tank's political arm, the American Energy Alliance, gave Trump its first political endorsement.

More: *The Hill*

Survey: Americans Willing To Pay 15% Carbon Tax

Americans are willing to pay almost 15% more for energy each year in the form of a carbon tax, according to a paper published Thursday in the journal "Environmental Research Letters."

A survey of 1,126 U.S. adults conducted last year between Nov. 18 and Dec. 1 found the average American would be willing to spend $177 per year more on energy when compared with electricity rates in each state.

The survey asked respondents to select from 10 options as to how they wanted to see the money generated from a carbon tax spent. Nearly 80% said they wanted the money to be invested in wind and solar.

More: *HuffPost*

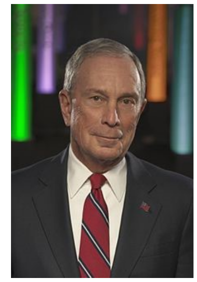
Solar Markets Growing in States that Voted for Trump

Eight of the 10 fastest-growing U.S. solar markets between the second quarters of 2016 and 2017 were Western, Midwestern or Southern states that voted for President Trump, according to data provided to Reuters by GTM Research.

Alabama and Mississippi led the pack. Six of the 10 states that installed the largest amounts of solar power over the past year were led by Republicans. Of those, Utah, North Carolina and Texas each installed more than 1 GW.

More: *Reuters*

Michael Bloomberg Giving $64M to Fight Against Coal



Bloomberg

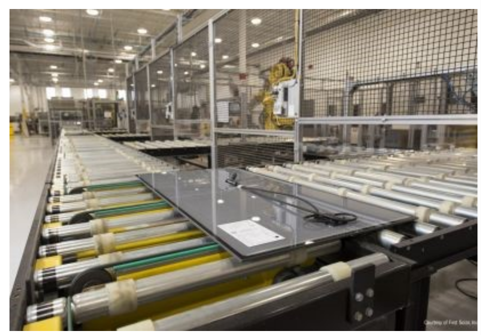
The day after EPA Administrator formally announced the agency was repealing the Clean Power Plan, former New York Mayor Michael Bloomberg announced that he is giving $64 million to the Sierra Club and other environmental groups to expand their campaign to retire U.S. coal plants.

The funds will support an effort to close 60% of the plants by the end of 2020 by working with mayors, governors, utility regulators and private sector leaders to make it easier for solar and wind power to compete.

Mr. Bloomberg also called Energy Secretary Rick Perry's Notice of Proposed Rulemaking on grid resiliency pricing one of the "worst ideas" that has ever come out of Washington — "and that's saying a lot."

More: *Bloomberg*

First Solar Asks ITC for Remedy in Trade Case



| *First Solar*

First Solar broke ranks with the Solar Energy Industries Association and is asking the International Trade Commission for a remedy that protects U.S. cell and module manufacturers in the trade case brought by Suniva and SolarWorld Americas.

In a letter filed last week with the ITC, First Solar said it was negatively impacted by imports of crystalline silicon PV products in 2016.

First Solar, which is a board member of SEIA, wrote that U.S. solar manufacturers need protections from these imports and that an effective remedy can exist together with continued growth in U.S. solar demand. It did not offer a solution.

More: *Greentech Media*

STATE BRIEFS

Report Finds 2.6 GW of 'Uneconomic' Coal in Midwest

Some 2.6 GW of coal capacity across six Midwestern states is uneconomic compared with cleaner alternatives, according to a report issued last week by the Union of Concerned Scientists.

The report identifies as uneconomic two coal units at DTE Energy's Belle River plant in eastern Michigan, three in Indiana and one in Illinois, collectively representing 2.6 GW of capacity. Overall, coal-fired generation declined across the Midwest from 2008 to 2016, ranging from a 19% decline in Wisconsin to a 47% decline in Ohio.

Nationwide, 21% of coal-fired generation capacity in 2016 is currently considered uneconomic, and an additional 18% of national coal-fired capacity is covered by announcements of closure or conversion to natural gas.

More: Midwest Energy News

MINNESOTA

Conservative Group: Wind not Living up to What Was Promised

Wind power in the state is not living up to what its backers promised, a local conservative think tank said last week.

A report written for Center of the American Experiment concluded prices have risen, carbon dioxide emissions haven't dropped and more than $10 billion has been spent on wind farms that do not save money or reduce pollution.

Lt. Gov. Tina Smith and Clean Energy Economy Minnesota Executive Director Gregg Mast disputed the findings, saying wind is the cheapest form of power.

More: Grand Forks Herald

NEW HAMPSIRE

Eversource Inks Deal to Sell Power Plants

Merrimack Station | *Eversource Energy*

Eversource New Hampshire on Thursday announced a deal to sell about a dozen power generation facilities, completing electric deregulation in the state.

If approved by the Public Utilities Commission, Eversource's three large fossil generation facilities and two remote combustion turbines will be purchased by Granite Shore Power, a newly formed 50-50 partnership between Atlas Holdings and Castleton Commodities International, for $175 million. Eversource's nine hydroelectric facilities will be acquired by Hull Street Energy, an electric industry-focused private equity firm, for $83 million.

Under the proposed purchase agreements, the new owners must keep the plants in service for at least 18 months.

More: New Hampshire Union Leader

UTAH

University Plans to Reduce Carbon Emissions by 25%

The University of Utah announced last week that it plans to reduce its total carbon emissions by 25% by sourcing 50% of its electricity from solar and geothermal energy sources.

The university signed an agreement with Cyrq Energy and Berkshire Hathaway Energy Renewables to provide 20 MW of geothermal energy and 10 MW of solar energy for 25 years. Rocky Mountain Power will facilitate the purchase and delivery through green tariffs.

The agreement is the largest long-term green power contract of any U.S. university, according to EPA's Green Power Partnership rankings.

More: Clean Technica

VIRGINIA

State Seeks Proposals for EV Charging Network

The state last week issued a request for proposals for a statewide charging network for electric vehicles.

The $14 million in funding for the project is coming from the state's portion of the Volkswagen settlement over the automaker's diesel emissions cheating scandal.

Responses are due by Nov. 6.

More: The Associated Press

WEST VIRGINIA

Delegation Supports DOE Resiliency NOPR

The state Congressional delegation wrote to FERC on Friday expressing its support for Energy Secretary Rick Perry's Notice of Proposed Rulemaking on grid resiliency pricing.

The letter pointed to the 2014 polar vortex as an example of a potentially catastrophic blackout that was avoided because coal units that were scheduled to retire remained available to be brought back online to meet demand.

"Short-term marginal fuel price, regulatory overburden, subsidy and policy mandate advantages for intermittent sources have rendered many baseload units uneconomical," the letter says.

More: RM18-1

Unfazed by Obstacles, Clean Line's Skelly Focuses on Future

Continued from page 1

had not obtained approvals from all the counties it would cross, Skelly turned to his staff and said, "We're not giving up."

Two weeks after that ruling, Clean Line filed an updated application for a certificate of convenience and necessity and asked for a rehearing. (See *Clean Line Seeks Rehearing on Grain Belt Rejection*.)

The commission rejected that request Sept. 19. This time Clean Line responded by hiring former Missouri Gov. Jay Nixon and his law firm as Grain Belt's legal counsel.

Nixon's first bit of advice? Take the case to the Missouri Court of Appeals' Eastern District, because the Western District had greased the skids for the PSC's previous rejection when it ruled that an infrastructure project must secure approvals from each county it crosses. (See *Clean Line Ponders Options After Grain Belt Rejection*.)

Clean Line did just that on Sept. 19.

Staying Power

Skelly does not easily take "no" for an answer. Developing long-term projects requires vision and staying power, something Skelly learned as a founding partner of the Rain Forest Aerial Tram in Costa Rica's rainforest. Skelly had come to the country as a Peace Corps volunteer after earning a bachelor's in economics from the University of Notre Dame and an MBA from Harvard Business School.

Tenacity also was essential in his role developing wind farms as employee No. 3 for Zilkha Renewable Energy in the 1990s. Skelly was the firm's chief development officer when it became Horizon Wind Energy after Goldman Sachs bought it in 2005. The banking giant sold Horizon (now EDP Renewables North America) for $2.2 billion in 2007.

Skelly then took a brief stab at politics, but after an unsuccessful run for Congress as a Democrat in Texas' 7th District (he lost by 13 points), he turned his attention back to the power industry and wind energy.

Sensing an opening, he founded Clean Line in 2009. Skelly had financial backing from Houston's Zilkha family, which had also bankrolled the wind company, and ZBI Ventures, owned by the Ziff family of New York.

Clean Line's business model is building long-distance transmission lines to deliver wind energy to urban population centers. "We thought transmission was going to be the linchpin of expanding wind energy," Skelly said. "If you look at the right technical solution to move lots of wind a long distance, you pretty quickly come to the conclusion that DC lines are the right answer. For anything over 100 miles [long], DC makes more sense. Then, thinking about it further, it was clear that the incumbents weren't going to do this. It's not their job to move energy to the Southeast or PJM. Their job is to focus on native load" and meeting demand.

"That felt like an opportunity for an individual to come in and tackle this job. No one else is going to do it."

HVDC can cost as much as $2 million a mile, according to Clean Line. The high capital costs and the regulatory obstacles that have delayed construction led the company to seek additional financial backers. The company, which has almost 40 employees, has no current source of revenue.

In 2012, National Grid USA announced it was investing $40 million for about a 40% stake in Clean Line. In 2015, Bluescape Resources, an energy investment and operating company headed by former TXU Chairman and CEO C. John Wilder, agreed to spend up to $50 million for equity in Clean Line, with the potential to invest more in the company's transmission projects.

Clean Line spokeswoman Sarah Bray said Bluescape is now the company's "principal investor," although National Grid, ZBI and the Zilkha family have retained equity stakes.

Project development for Grain Belt began in 2010, and in late 2012, the company was hoping to begin construction as early as 2015. Clean Line now says construction could begin in 2019, with the project operational as soon as 2021.

Like jugglers, Skelly and his staff must keep their eyes on many balls at the same time. The project teams are regionally based, but they enjoy legal, financial, communications,

Continued on page 38

Besides Grain Belt, Clean Line is developing four other projects. Below is a description of the projects and their current status, contrasted with the company's projections from 2012, where applicable:

- The Rock Island Clean Line, a 500-mile project from northwest Iowa to Illinois, delivering 3,500 MW of wind energy. The project was originally expected to be operational in 2017. But on Sept. 21, the Illinois Supreme Court rejected the Rock Island application because Clean Line held only an option agreement on a parcel for a converter station — rather than a completed purchase agreement — when it applied to the Illinois Commerce Commission. The company said the ruling will cause "great delay" for the project. "Although we are disappointed with the Supreme Court ruling on the Rock Island Clean Line, on the positive side, the decision did not impact the authority of the ICC, and the court made clear that we have an opportunity to refile with the ICC at a later date," the company said in a news release. The company hasn't decided on its next steps.
- The Plains & Eastern Clean Line, an approximately 700-mile project from the Oklahoma Panhandle through Arkansas to Memphis, Tenn., delivering 3,500 MW of power to the Tennessee Valley Authority and 500 MW to Arkansas. The company is involved in commercial negotiations with potential customers, both wind generators and loads seeking power. It will begin construction once it has contracts for 2,000 MW of capacity.
- The Centennial West Clean Line, a 900-mile project delivering 3,500 MW of renewable energy from New Mexico and Arizona to California. The company had expected construction to begin in 2017 and be operational in 2019. Development has slowed down while the company works on its other projects.
- The Western Spirit Clean Line, a 140-mile project complementing the Centennial West project, delivering 1,000 MW of renewable power from east-central New Mexico to markets in the western U.S. Clean Line acquired the project, originally named Power Network New Mexico, in 2013. Construction, which will take about one year, could begin by the end of 2018.

Unfazed by Obstacles, Clean Line's Skelly Focuses on Future

Continued from page 37

environmental and other support from Clean Line headquarters in downtown Houston, where black-and-white photographs of rock stars and the New York punk scene hang on the walls.

"You would think in eight years, you would have sort of a lull, but it's a sort of a mad dash every day to move these projects forward," Skelly said. "It's more like an Ironman [Triathlon], not a marathon. It's more like a decathlon, but it goes on for eight years."

Projects that take so many years to put together will inevitably face changes at the federal, state and utility commission levels, Skelly said.

"One of the things you want to think about is putting together projects that can last through administrations," he said.

One example: In March, the Arkansas congressional delegation — all Republicans — asked Energy Secretary Rick Perry to "preserve states' rights" and reverse the Department of Energy's decision to partner on the Plains & Eastern Clean Line over the objections of Arkansas officials. (See *DOE Agrees to Join Clean Line's Plains & Eastern Project*.) The department had invoked Section 1222 of the Energy Policy Act of 2005, which, the legislators said, "risks codifying into law the practice of federal eminent domain seizures."

The lawmakers also are sponsoring a bill that that would prevent the department from using eminent domain for Section 1222 transmission projects without the approval of both the governor and utility commission of affected states.

The project also has drawn the ire of Sen. Lamar Alexander (R-Tenn.), a member of the Energy and Natural Resources Committee, who said it could burden the Tennessee Valley Authority with expensive wind power it does not need.

TVA has signed a memorandum of understanding with Clean Line, which has begun buying rights of way for the project. But neither TVA nor any other utility has signed a contract to buy the power the project would transmit.

Bray said she's confident that Perry, the former Texas governor, will see the value of the project. "He's seen the benefits of wind power first hand," she said, citing the economic growth the state's Competitive Renewable Energy Zone projects brought to rural Texas.

Skelly has said seeking DOE authority for the Grain Belt and Rock Island lines is an option but not his first choice because it is slow and costly.

Nothing to Show

Skelly doesn't have to be reminded that Clean Line has yet to see a project come to completion, but that's through no fault of the staff, he says.

"We haven't done anything yet. We haven't built anything yet," he said. "You have to have a very motivated team. You have to be tremendously tenacious, you have to be creative. You've got to think long, long term. You have to have a team that works."

Skelly said that while landowners' opposition to transmission projects is "understandable," the pushback from within the industry is more frustrating.

"We need to do a better job in embracing new ideas and innovation," Skelly said. "If you separate [transmission and generation], you generally get more innovation. You don't have the same level of common interests."

Pointing to Commonwealth Edison's opposition to the Rock Island project in Illinois, he said, "Why are they doing that? They're doing that to protect their generation. If you look at what other countries are doing to build up their grid, they are embracing new ideas and innovation. They're coming up with cost-effective solutions and they're getting big projects done."

ComEd did not respond to a request for comment.

In May, ComEd asked the Illinois Supreme Court to dismiss Clean Line's appeal seeking to overturn an appellate ruling that reversed the Illinois Commerce Commission's approval of the project. ComEd said the project had changed since the ICC's approval in 2012.

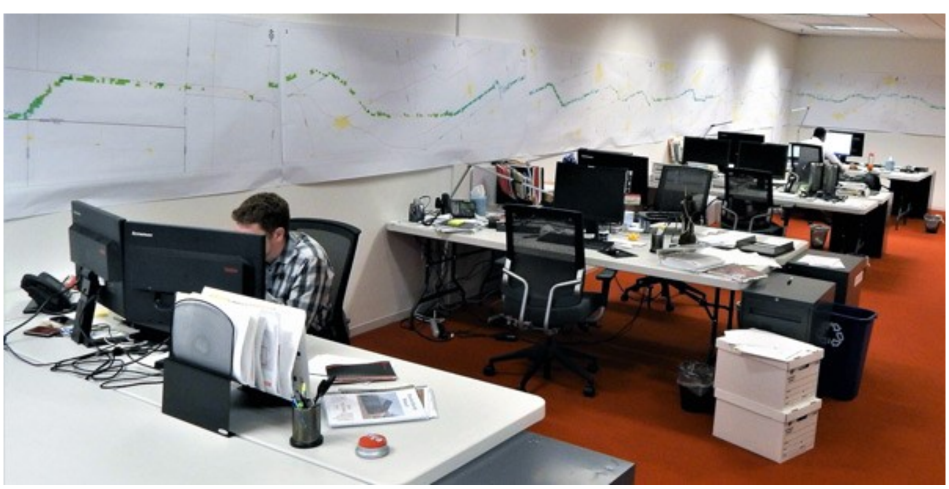
Interregional Planning

Skelly is among those who have been frustrated that FERC Order 1000 hasn't resulted in interregional transmission projects. WIRES, an industry organization supporting transmission investment, says the order has failed to produce true interregional planning because of inconsistencies in how neighboring regions evaluate projects.

"It is common for projects that are shown to provide benefits in interregional evaluations to fail regional evaluations for inclusion in regional plans," the group said in comments following a FERC technical conference last year (AD16-18). (See *Five Years Later, FERC Takes Another Look at Order 1000*.)

WIRES also says transmission planning should model "a broader range of plausible market conditions, system contingencies and public policy environments" to consider the "flexibility benefits and insurance value that a more robust interregional transmission infrastructure can offer."

In its grid study released in August, DOE called for a review of "regulatory burdens for siting and permitting" of transmission and actions to "accelerate the process and



Project maps stretch around Clean Line's offices in Houston. | © *RTO Insider*

Continued on page 39

Unfazed by Obstacles, Clean Line's Skelly Focuses on Future

Continued from page 38

reduce costs." (See Perry Grid Study Seeks to Aid Coal, Nuclear Generation.)

Building Relationships

Clean Line has worked hard in Missouri to gain community support for Grain Belt. The company signed up more than three dozen cities to purchase about 100 MW of power from the project; many of the cities also offered statements of support. That $525 million project, the company says, will save the state's consumers $10 million annually and create more than 500 permanent jobs to maintain and operate the wind farms and the transmission line.

"You have to build alliances," Skelly said. "We've got support from labor groups, environmental groups, business groups, from political leaders … doing these projects without building those types of alliances would be really, really difficult."

That relationship-building extends to RTOs. While SPP, MISO and other grid operators don't manage long-distance DC lines, their responsibility for grid reliability comes into play when interconnections are discussed.

Clean Line also must "fit within the context of how they do their market operations," Skelly says.

The RTOs' "paradigm is around the cost allocation of projects built by incumbents, which comes out of their planning process. Their planning process doesn't plan around significant transmission exports. We have to make sure and work with them, so our projects fit within the context of those plans."

Skelly said Clean Line recently spoke with an SPP member concerned about congestion caused by wind farms in the RTO's western footprint. "They said, 'We used to think you were too early. Now, we can't get you to build your project soon enough,'" he recalled.

'Preservation and Adaption'

While his business is focused on energy sources of the future, Skelly is also a history buff and preservationist. He and his wife, Anne Whitlock, live in a renovated firehouse in East Houston, which was recently recognized by Preservation Houston as a "shining example of preservation and adaption." Nearby sit six Victorian homes that Skelly had moved and refurbished.

Firestation No. 2 and the other buildings served as a refuge for residents forced from their homes during the flooding during Hurricane Harvey, an act that drew attention from *The Washington Post*.

Skelly writes occasional op-eds in the *Houston Chronicle*, in which he has advocated for making the car-centric city more pedestrian- and cyclist-friendly.

Optimistic About the Future

Meanwhile, an optimistic Skelly continues to look to the future. Although federal production tax credits for wind projects will expire at the end of 2019, he thinks continued technological advances in wind turbines will compensate for that loss.

The renovated Firestation No. 2 | © *RTO Insider*

"We thought that the combo of open-access, low-cost wind [that is] relatively easy to permit … would result in an over-build of wind," requiring transmission to move the excess energy to load centers, he said. "We didn't think that would happen until 2030, but it's upon us now. Over time, we are moving to a leaner energy mix, there's no question. Economics favor that. That's just reality.

"There's a lot of people pulling for us. I don't think [demand for renewable energy] is going away any time soon. There are very large consumers of power in this country that care about carbon [emissions], and they're putting their money where their mouth is in how they source electricity."

CPP Supporters Hope for Action by DC Circuit

Continued from page 1

arguments on that and other legal challenges to the plan.

In August, however, the D.C. Circuit agreed to hold the case in abeyance after President Trump's executive order calling on EPA to reconsider the rule.

Judicial Economy

Attorney Tim Profeta, director of Duke University's Nicholas Institute for Environmental Policy Solutions, said that the D.C. Circuit should now rule on the case because of "the logic and judicial economy of the situation."

"You've got the court of jurisdiction having heard *en banc* the precise legal arguments that are being made in this rule," he said in an interview. "It's fully briefed. It's fully argued."

If the court doesn't act on the case before it, he said, "they will probably have the same case before them in new litigation that would have to be briefed and argued all over again. … There's no reason for the court to waste its time and taxpayers' money to relitigate the case," he said.

David Doniger, director of the Natural Resources Defense Council's Climate & Clean Air program, agreed. The court "could rule before [Pruitt] gets to the finish line on the repeal," he said during a press conference Oct. 10. "At least some of the judges there are looking at their wristwatches."

Doniger was referring to the concurrence filed by Judges David S. Tatel and Patricia A. Millett on Aug. 8, when the court held the case in abeyance and ordered EPA to file reports monthly detailing the status of its

Continued on page 40

CPP Supporters Hope for Action by DC Circuit

Continued from page 39

review. The D.C. Circuit's action followed the Supreme Court's February 2016 stay preventing EPA from implementing the rule pending the legal challenges.

"As this court has held the case in abeyance, the Supreme Court's stay now operates to postpone application of the Clean Power Plan indefinitely while the agency reconsiders and perhaps repeals the rule," the two judges wrote. "That in and of itself might not be a problem but for the fact that, in 2009, EPA promulgated an endangerment finding, which we have sustained. … That finding triggered an affirmative statutory obligation to regulate greenhouse gases. Combined with this court's abeyance, the stay has the effect of relieving EPA of its obligation to comply with that statutory duty for the indefinite future."

During the oral arguments, Millett and Tatel had indicated sympathy for the Obama administration's position that the CPP complied with Section 111(d). The term "best system of emission reduction" is "an awful broad grant" from Congress, Tatel said. "It says best system of emissions reduction," he repeated twice, emphasizing "system." (See *Analysis: No Knock Out Blow for Clean Power Plan Foes in Court Arguments*.)

Status Report

EPA filed a status report late Oct. 10 informing the court of the proposed repeal and asking it to continue holding the case in abeyance. "EPA will be signing in the near future an Advance Notice of Proposed Rulemaking that will solicit information on systems of emission reduction that are in accord with the legal interpretation that has been proposed by EPA," said the report, which was signed by Deputy Assistant Attorney General Eric Grant.

Doniger said NRDC, which intervened in the case on behalf of the Obama EPA, has the right to defend the CPP now even if the agency no longer does.

"Depending on what [EPA does regarding the delayed ruling], we'll respond," he said. "If they don't do anything, we may do something [to request a ruling.] … We deserve a resolution of the legality of the Obama rule."

If it chooses not to rule now, the court could set a deadline for final EPA action or grant additional short-term delays "to keep the pressure on," Doniger said.

An EPA spokeswoman declined to comment on the status of the D.C. Circuit case, referring questions to the Department of Justice, which also declined to comment.

During oral arguments, Justice Department attorney Eric Hostetler told the court it should back the CPP under the Supreme Court's *Chevron* decision, which held that courts should defer to agencies' interpretations of the laws they are charged with enforcing unless the court finds their actions unreasonable. "This is far from the first time EPA has relied on generation-shifting," Hostetler said. EPA's rule, he added, is a "proper and sensible" response for the "most urgent threat that our country has ever faced."

Returning to Prior Interpretation

CPP critic Jeff Holmstead, a partner with Bracewell and former EPA assistant administrator for air and radiation, had a very different view.

"In today's proposal, EPA is not breaking any new legal ground. It is simply returning to the position that EPA had taken, under all prior administrations except the Obama administration, regarding the way in which industrial facilities can be regulated under a particular provision of the Clean Air Act," he said in a statement.

"Under the CPP, the Obama EPA claimed that this 45-year-old provision actually gave it the extraordinary power to restructure the entire U.S. power sector — requiring that coal-fired power plants be shut down and replaced by wind and solar facilities favored by the Obama administration. Virtually every major business group joined 27 states in challenging this claim, arguing that the CPP was an example of historic regulatory overreach."

Single Source

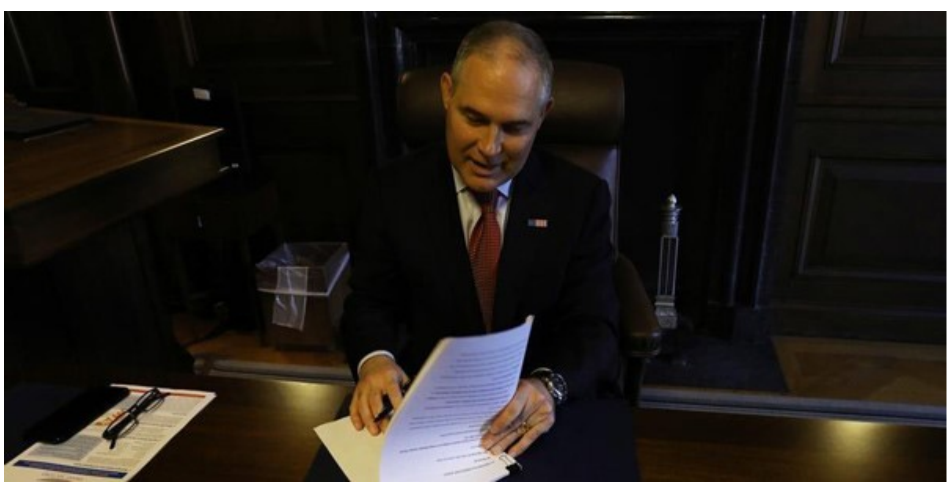
The draft NOPR said EPA will interpret the CAA's "best system of emission reduction" as referring to measures "that can be applied to or at an individual stationary source. That is, such measures must be based on a physical or operational change to a building, structure, facility or installation at that source, rather than measures that the source's owner or operator can implement on behalf of the source at another location."

The draft indicated EPA will not seek to reverse the agency's 2009 finding that GHGs endanger public health.

EPA's Obligation to Act

Doniger said EPA's "legal obligation is to have an effective standard and one that reflects how the power system actually works."

"Pruitt is operating under a fictional view — a 125-year-old view — that each power plant is operating by itself and serving the surrounding community alone. … Pruitt is constructing a legal argument based on a factual fiction — it basically assumes that there is no grid and there is no interconnection. And that's among the reasons why his legal view will not prevail."



EPA Administrator Scott Pruitt | *EPA*