RTO Insider

Your Eyes and Ears on the Organized Electric Markets

ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

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FERC Jurisdiction over Demand Response in Peril as Supreme Court Splits

4-4 Deadlock Would Let EPSA Ruling Stand

By Rich Heidorn Jr.

WASHINGTON — The Supreme Court's liberal wing indicated support Wednesday for FERC's jurisdiction over demand response, but the commission faced harsh questions from conservatives Antonin Scalia and Chief Justice John Roberts and swing vote Anthony Kennedy.

Kennedy and Scalia challenged Solicitor General Donald Verrilli's arguments on behalf of FERC, with Kennedy referring to them as "circular" logic and Scalia expressing opposition to the commission's "fiddling around" with retail rates.

Justices Stephen Breyer, Sonia Sotomayor and Elena Kagan were equally critical of attorney Paul Clement, representing the Electric Power Supply Association. Sotomayor interrupted Clement early in his argument, demanding "where is that written down?" after the attorney categorized FERC's intent as trying to reduce retail demand.

EPSA filed the lawsuit challenging FERC Order 745, which set rules for compensating DR in RTO energy markets. In May 2014, the D.C. Circuit Court of Appeals vacated the order, saying DR is a retail product and thus subject to state, not federal, jurisdiction.

Conservative Justice Clarence Thomas and liberal Ruth Bader Ginsburg were silent during the one-hour argument, which drew numerous RTO stakeholders as observers.

If the justices side with their normal allies, the court could end up deadlocked 4-4, meaning the D.C. Circuit ruling would stand. Justice Samuel Alito has recused himself in the case.

"If the court does cast a four-to-four vote at its private conference on Friday, and decides that [is] the most that it can do, that result would be announced promptly, perhaps as early as next Monday," *SCOTUS Blog* predicted.

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SPP, MISO Reach Deal to End Transmission Dispute

By Amanda Durish Cook and Tom Kleckner

INDIANAPOLIS — MISO and SPP have filed a settlement agreement with FERC allowing MISO to use the SPP transmission system to transfer power freely between its North and South regions.

MISO North-South border

The settlement (ER 14-1174, *et al.*) eliminates the $9.57/MWh hurdle rate established in 2014 after SPP complained that MISO's use of the SPP grid exceeded a 1,000-MW transfer limit in their joint operating agreement.

The agreement also supplants MISO and SPP's Operations Reliability Coordination Agreement (ORCA), set in place in early 2014 to address capacity sharing across the region.

Six transmission owners outside of MISO and SPP — Southern Co., the Tennessee

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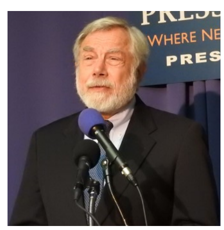
Public Power Group Proposes to Buy Pepco's DC Assets

Exelon Would Keep Md., Del., NJ PHI Units

By Rich Heidorn Jr. and Suzanne Herel



DCPP board member John Chelen

WASHINGTON — A newly formed advocacy group on Friday filed its intent to acquire the district assets of Pepco Holdings Inc. and transform it into a not-for-profit utility that it said will generate about $1 billion in savings over the next 20 years.

Not having to pay federal taxes or dividends to shareholders would "unlock" $150 million a year in savings — or about $60 million after subtracting debt — that could be spent on reliability, improvements and rate reductions, said Michael Siegel one of D.C. Public Power's four board members, in announcing

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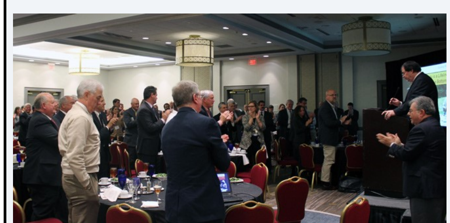

- Former EPA Official: CPP won't Survive (p.2)
- Bowring Concerned over Hourly Offers (p.3)
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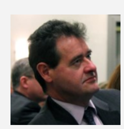

PJM Board Welcomes Ott into New Role as CEO

Andy Ott is officially head of PJM, after spending a six-month transition period at the side of retiring CEO Terry Boston. (p.13)

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Former EPA Official: Clean Power Plan won't Survive

By Rich Heidorn Jr.

BALTIMORE — Former Environmental Protection Agency official **Jeff Holmstead** says he hasn't made predictions on how the courts will rule on previous environmental rules affecting the electric industry.

But Holmstead, former EPA assistant administrator for air and radiation, says he's very confident that the agency's new carbon emission rule, the Clean Power Plan, will not live long enough to be implemented.

"I have not been out there predicting any of the other rules would be struck down," said Holmstead, now a lobbyist for utilities and the coal industry, during a panel discussion that opened the Organization of PJM States Inc. annual meeting last week.

"I had my concerns about [the Mercury and Air Toxics Standards]; I had concerns about [the Cross-State Air Pollution Rule]; but I was pretty confident they would be upheld in court. … But this rule is completely different from anything that EPA's ever done before. … If this gets to the Supreme Court, there are right now almost certainly five justices that would vote to overturn it."

Although the court has said EPA can regulate CO_2 emissions, Holmstead said, the agency must do so by setting an emission rate based on the best technology available. "It cannot require an existing source to go out and pay another entity to do something else that has nothing to do with the particular plant," he said.

"The only program I think that would clearly withstand judicial scrutiny would be an inside-the-fence line, efficiency-based approach. The reason EPA didn't do that is because it doesn't get you very much," he said. "The reason they've taken this big, legally vulnerable step is because that's the only way they thought they could get meaningful reductions."

Holmstead — who served in both Bush administrations and now lobbies for Arch Coal, Southern Co. and Duke Energy as head of the environmental strategies group at Bracewell & Giuliani — is hardly a neutral observer. He is loathed by environmentalists, with Greenpeace labeling him "King Coal's Mercury Pollution Lobbyist."

But none of the other members of the panel — which included PJM's Mike Kormos and officials from Exelon, American Electric Power, the American Wind Energy Association and the Southern Environmental Law Center — challenged Holmstead's legal analysis, although some questioned his prediction that a Supreme Court ruling could come by the end of 2017.

At a conference in D.C. on Tuesday, EPA Associate Assistant Administrator Joseph Goffman said the rule's building blocks — which include increased dispatch of natural gas plants and renewables — "reflect what states and utilities told us was the 'Best System of Emission Reduction.'"

Holmstead pointed to four dates that will determine the rule's fate:

In the first quarter of 2016, he said, a decision is likely by the D.C. Circuit Court of Appeals on requests for a stay (highly unlikely, he acknowledges).

The next milepost will be the 2016 presidential election. "The [EPA] administrator and the administration have been telling people around the world that once this regulation is finalized it will be very hard for anyone to change it. It becomes a part of the law and what's done is done," he said.

"There are some rules that are very difficult for a new administration to change, for legal reasons or practical reasons. But this is not one of those regulations. So I can say with some confidence that if there is a Republican administration … the rule will fairly quickly be revoked."

Holmstead sees a D.C. Circuit court ruling on the merits of the rule by the end of 2016 because the Obama administration has said it wants to defend it before the president leaves office.

Because of the expedited schedule, a Supreme Court ruling could come by the end of 2017, he said, though others say 2019 is a more realistic timeline.

And if the rule is thrown out?

"At that point we're probably all back on Capitol Hill talking about legislation," he said. "And the good thing about legislation of course is that it really does provide you much more certainty.

"The fact that EPA will ultimately likely regulate [carbon] regardless of how this rule comes out doesn't tell you very much about your future investment decisions. Because you just don't know if EPA can do anything that's at all aggressive."

Farewell to Boston

On his second-to-last day as CEO of PJM, Terry Boston receives a standing ovation from OPSI attendees for his farewell speech, "21st Century Power Grids, or 'The Future Ain't What It Used To Be,'" a humorous reflection on how the industry has changed through his career.

Boston will serve as CEO emeritus until the end of the year. Andy Ott now takes the helm. (See related story, *PJM Board Welcomes Ott into New Role as CEO*, p.13.)

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Bowring Concerned over Gaming of Hourly Offers; Role Under Capacity Performance

By Rich Heidorn Jr.

BALTIMORE — PJM Market Monitor **Joe Bowring** said last week that the RTO must include strong market-power protections in rules allowing generators to change their offers hourly.

Bowring also told a meeting of the Organization of PJM States Inc. Advisory Committee that he is concerned that the Monitor has no defined role in screening generator offers under the new Capacity Performance rules.

The annual meeting of the OPSI Advisory Committee is the one time per year that the Monitor and the PJM Board of Managers meet publicly face-to-face. Both Bowring and PJM Chairman Howard Schneider agreed that their relationship is strong despite their frequent disagreements on Tariff filings.

"I think part of maintaining the positive relationship we've had with PJM over the years is understanding exactly what our roles are," Bowring said.

And that, he said, is why he is raising his concerns that the CP rules give the Monitor no formal role in evaluating physical parameters in offers from generators.

Although the process approved by FERC requires PJM to consider the Monitor's input, Bowring said he would prefer a parallel review process similar to that used in determining generators' avoidable cost rate, with PJM ensuring compliance with its Tariff and the Monitor screening for market power. (The ACR of a generation resource is the fixed costs necessary to allow a generation resource to remain in commercial operation.)

"Our process can be much more contentious than PJM's. It's a very different standard," he said.

If the Monitor disagrees with PJM on physical parameters under CP, Bowring said, "it could get messy."

"I think it's better to have a clear process where everyone understands what will happen in the event there's a disagreement. And it's highly likely there will be one — there are different standards being applied."

Board Member Jean Kinsey said she thinks the process proposed by PJM and accepted by FERC should be given time to work.

"The process that's being used for PJM and the Market Monitor to jointly sit down and see the physical parameter data that's being submitted simultaneously is, it seems to me, a very good process because … you're collaborating on your thoughts about whether it's good, bad or indifferent," Kinsey said. "These are physical parameters. They're more engineering-centric than the cost-based [parameters]. … If a year from now, a year and a half, it seems not to be working, we will re-address it just like we do everything else."

Market Power Concerns

Bowring also said that while he supports a move to allow generators to change their offers hourly, he is concerned that it could lead some to exploit weaknesses in PJM's market power mitigation rules.

In June, FERC ordered PJM to change its Tariff to allow generators to submit day-ahead offers that vary by hour and to update their offers in real time (EL15-73). PJM is the only RTO that doesn't allow such variable offers. (See *Duke, ODEC Denied 'Stranded' Gas Compensation*.)

PJM must make a compliance filing spelling out how it will implement the change by Nov. 1. The Generator Offer Flexibility Senior Task Force will be meeting Wednesday to discuss the proposal.

He said the introduction of hourly offers has impacts on both local market power — which PJM polices through the three pivotal supplier test — and aggregate market power.

"There are various ways to game the three pivotal supplier test and the impact of that is going to be made much worse with hourly flexibility and hourly offers unless they're addressed," he said.

Aggregate market power concerns arose during the January 2014 polar vortex, when Bowring said "just a couple" of generation owners were pivotal — PJM needed their output in order to clear the market.

"In PJM there is no rule governing aggregate market power," Bowring said. "That's been fine to date, but with the hourly market flexibility it's not going to be fine anymore."

Bowring's suggestion: "If you change your offer in midday to reflect gas costs, that's fine. But you should not be allowed to increase your markup from $10 to $500 because you think the market is tight, you're pivotal and you can get away with it."

Elise Caplan of the American Public Power Association said capacity markets are not the optimal means for procuring new resources or retaining the most needed ones and should be voluntary. "We don't think that the capacity market should be the central place where resource decisions [and] resource procurement are made."

PJM's **Stu Bresler** said APPA's proposal sounds like "what's in place at MISO. … I really do believe that the PJM construct — the concept of a system-wide, region-wide capacity market — is the long-term, lowest cost solution for procurement of capacity resources. … I would not want to be in MISO's position."

OPSI Annual Meeting 2015

Artificial Island Allocation, Cost Caps Generate Sparks in OPSI Order 1000 Discussion

By Rich Heidorn Jr.

BALTIMORE — Delaware Public Service Commission Chairman Dallas Winslow took on PJM planners over the Artificial Island project and rival developers sparred over the enforceability of cost caps at a panel discussion on Order 1000 implementation at last week's Organization of PJM States Inc. annual meeting.

Opening up the session, PJM Vice President for Planning Steve Herling talked about how Order 1000 has increased planners' workload and noted how cost allocation, "previously an end result of the process, is now getting fed into the process at the beginning."

A slide in Herling's presentation elaborated, saying that stakeholders are attempting "to influence our decision-making based on who will pay rather than which project is the most cost-effective."

That didn't sit well with Winslow. "I'm not sure a project can be cost-effective if it doesn't cost the appropriate parties the burden of what they're benefitting from," he said.

Winslow called for a show of hands from other state regulators, asking: "What state in the room here would agree to pay voluntarily a cost allocation that made you pay 80% of the cost when you got 20% of the benefit?"

No one raised their hand.

While he didn't mention the project by name, Winslow's comments were a clear reference to the dispute over the cost allocation for the Artificial Island stability project.

Because the project is considered a lower-voltage facility, the cost of LS Power's plan — running a new 230-kV circuit from Salem, N.J., under the Delaware River to a new substation near the 230-kV corridor in Delaware — is being allocated almost entirely to Delaware and Maryland customers.

In an Oct. 9 filing in response to complaints from those states, PJM acknowledged that the cost allocation may "appear disproportionate" but took no position on whether FERC should reconsider the use of solution-based distribution factor (DFAX) methodology for divvying up the bill on such projects (EL15-95). (See *PJM: Artificial Island Cost Allocation Appears 'Disproportionate.'*)

Delaware PSC Chair Dallas Winslow © RTO Insider

Jodi Moskowitz, PSE&G © RTO Insider

Winslow called on PJM and its stakeholders to address the equity issues he said were raised by the dispute.

"There are times when you've got to stand up and say 'is this is fair or not?'" Winslow said. "Should we just kick it down the road to Washington D.C.? Or should there be a mechanism to address what clearly and objectively is a violation of law?"

Cost Cap

Last year, PJM planners recommended Public Service Electric & Gas be selected to construct a different solution for Artificial Island. PSE&G's winning proposal was estimated at $1.066 billion before planners eliminated two 500-kV lines from it.

Facing a barrage of criticism, PJM's Board of Managers rejected the proposal and reopened the project, allowing PSE&G and two other finalists to revise their proposals in response to LS Power's offer to cap its project cost at $171 million — $40 million to $90 million less than the PSE&G project.

After months of additional study and debate, the board awarded the project to LS Power, with smaller portions of the work to be done by PSE&G and Pepco Holdings Inc. (See *PJM Board OKs LS Power's Artificial Island Project Despite Objections*.)

The bitter feelings over that battle were apparent at the panel discussion as Jodi Moskowitz, senior director of transmission development and strategy for PSE&G, suggested a developer might be able to recover costs above its cap if it can be shown to have acted prudently.

"FERC has yet to approve a cost cap coming out of an Order 1000 process. So we're not sure at this point if cost caps are in fact legally enforceable," she said.

She noted that ITC Holdings has asked FERC for guidance on whether a cost cap constitutes a just and reasonable rate. Because the commission hasn't ruled, she said, "it is still very much an open question."

LS Power's Sharon Segner insisted the cap it agreed to was enforceable, saying it will be included in the designated entity agreement with PJM.

Workload Increasing

Herling said the volume of transmission proposals unleashed by Order 1000 has strained PJM's resources.

"Most reliability projects — 90% or more — are solved by relatively simple upgrades to existing infrastructure. And we would typically have worked in a collaborative fashion with the transmission owner to identify one or two options to solve that problem," he said. "Now we're getting four, five, six — as many as 26 — proposals to solve a given problem."

Herling said it added to the workload of not only the planners conducting the analyses but also the RTO's legal and finance staff, who help administer the process.

Herling noted that CAISO and SPP have sought to reduce the workload by eliminating the sponsorship approach: "Simply pick the best solution and put it out for bid."

But he said PJM wasn't willing to abandon the sponsorship model yet. "We see a lot of value in the sponsorship process," he said.

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Heard at OPSI

"The results of the CP auctions provide a path forward for the financially challenged nuclear generation," said Exelon's **Jason Barker.** "Unlike coal and gas units, in the face of declining market revenue, nuclear unit owners don't have the choice of throttling back reinvestment in their units. Our decision is effectively binary."

Ken Foladere of Tangibl disputed the idea that Capacity Performance was a giveaway to generators. "That's not the case. Yes, there are increased costs and I understand how members of [state commissions] and consumer advocates feel about that. … But there are also very large, increased risks as well."

Bill Fields, Maryland's senior assistant people's counsel, said it was critical to use capacity revenue to fund demand response programs. "You're asking them to basically turn off their air conditioning when it's hot outside, so they need some kind of incentive to do that, and the capacity revenue has been able to provide that." He said he is concerned that DR could be reduced when PJM transitions to 100% Capacity Performance and by the Supreme Court's decision in *FERC v. EPSA*.

"By virtue of having a winter measurement metric that differs from the summer — and in ways that prevent summer-peaking resources from delivering — we've made a construct that delivers less demand response from the summer-peaking resources, which to me seems counterintuitive and unproductive," said **Bruce Campbell** of EnergyConnect.

"Capacity Performance rules virtually eliminate the ability of summer demand response to continue as capacity resources," EnerNOC's **Katie Guerry** said.

"I think it's fair to say that Capacity Performance development and implementation were rushed," said **Robert Weishaar**, counsel to the PJMICC. "I think it's fair to say that the CP proposals were reactions to 1) the polar vortex and 2) generators' claims of revenue insufficiency. Some of those claims were transparent; some of those claims may not have been as transparent."

ISO-NE NEWS

Entergy Closing Pilgrim Nuclear Power Station by 2019

By William Opalka

Entergy announced Tuesday it will close its Pilgrim Nuclear Power Station in Plymouth, Mass., no later than June 1, 2019, marking the company's exit from the New England market.

The company blamed "poor market conditions, reduced revenues and increased operational costs" for the planned closure. The plant has come under increased scrutiny from the Nuclear Regulatory Commission, having earned the second-worst ranking for operational performance. (See *Federal Briefs*.)

The company said it would cost $45 million to $60 million in direct costs, plus any additional capital expenses, to comply with NRC requirements.

"The decision to close Pilgrim was incredibly difficult because of the effect on our employees and the communities in which they work and live," Entergy CEO Leo Denault said in a statement. "But market conditions and increased costs led us to reluctantly conclude that we had no option other than to shut down the plant."

The 680-MW plant began operations in 1972.

The company blamed low current and forecast energy prices caused by shale gas. The Energy Information Administration reported last week that January 2016 forward contracts for on-peak power in New England are trading at about $90/MWh, versus $190/MWh a year ago.

Entergy says the falling prices would lower annual revenue from Pilgrim by more than $40 million.

It also blamed what it called "wholesale energy market design flaws" that suppress energy and capacity prices, state subsidies for renewable energy and a recent proposal to import Canadian hydropower. (See *Baker: Hydropower Contracts Best Way to Lower Costs*.)

The merchant plant was relicensed three years ago by NRC and can operate through 2032. But the commission's decision to place Pilgrim in column 4 of the reactor oversight process action matrix put it in the unwelcome position of being one of three of the country's 99 nuclear plants so designated.

"We have invested hundreds of millions of dollars to improve — first and foremost — Pilgrim's safety, as well as its reliability and security, but face increased operational costs and enhanced Nuclear Regulatory Commission oversight," the company said. "We also take into account the effect on our stakeholders of operating over the long-term if it is not economically viable to do so." Entergy said the exact date for closing the plant would be decided in the first half of 2016. It already notified ISO-NE that the plant will not be available as a capacity resource starting in mid-2019.

ISO-NE's 10th capacity commitment period begins in June 2019, with its Forward Capacity Auction slated for February 2016.

Generators are required to notify the RTO by Monday if they will participate in the 2016 auction.

Nuclear power generated 34% of New England's power in 2014. Pilgrim represents almost 17% of the region's nuclear capacity.

ISO-NE could ask Entergy to keep the plant online if a study indicates it is needed for grid reliability. If Entergy agrees, it would receive out-of-market payments. But the RTO does not have the authority to prevent a resource from retiring.

The closure of Pilgrim will mark Entergy's exit from New England. The company closed the 615-MW Vermont Yankee nuclear power plant at the end of 2014 and last week announced the sale of a 583-MW natural gas plant in Rhode Island. (See *Entergy Sees Big Gain on Sale of RI Gas Plant to Carlyle*.)

The Pilgrim nuclear decommissioning trust had a balance of approximately $870 million as of Sept. 30, which is approximately $240 million above what NRC requires for license termination activities, Entergy said.

Entergy bought the plant in 1998 for $80 million from Boston Edison. Entergy Nuclear was the first company in the nation to purchase a nuclear plant through the competitive bid process, it said.

Almost 5 Years Later, FERC Denies NSTAR Market Power Complaint

By William Opalka

FERC on Thursday denied rehearing of its approval of Constellation Energy's acquisition of five New England power plants, a deal proposed five years ago (EC10-85).

NSTAR Electric challenged the sale of five power plants in the Boston area worth about 2,654 MW from various entities to Constellation for $1.1 billion. The sale represented about 8% of the generation fleet within the ISO-NE footprint at the time.

NSTAR claimed that the deal would harm competition in the New England energy market. FERC, however, approved the transaction as in the public interest.

NSTAR requested a rehearing, saying in part that two gas-fired plants originally owned by Mystic Power were susceptible to common mode failure because they both depended on a connection to a Distrigas liquefied natural gas terminal for their fuel. This condition, NSTAR said, could lead to the simultaneous loss of fuel supply, which would drive up consumer costs due to an increased reserve requirement by ISO-NE.

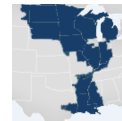
FERC in its order last week said this infrastructure issue was outside of the scope of the acquisition and noted that a 2006 settlement regarding the issue imposed conditions on the plant owners and subsequent buyers.

While the FERC docket for the case has been dormant since June 2011, when Constellation filed a response to NSTAR's complaint, the companies have undergone significant changes of their own.

Original plaintiff NSTAR merged with Hartford, Conn.-based Northeast Utilities in April 2012 to create the region's largest distribution utility that has since been renamed Eversource Energy.

Constellation was acquired by Exelon in March 2012. In 2014, Exelon sold one of the plants in the original deal, the 688-MW Fore Generating Station, to Calpine for $530 million, marking that company's entry into New England.

MISO News



Latest Order 1000 Revisions Under Stakeholder Scrutiny

By Amanda Durish Cook

MISO's latest Order 1000 compliance filing — which revises the developer selection process and outlines a *pro forma* selected developer agreement (SDA) — has drawn criticism from developers and transmission owners seeking additional changes (ER15-2657).

MISO's proposed Tariff changes, filed Sept. 16, include relaxing deadlines and participation requirements for the annual transmission developer qualification process to allow for "broader participation" in the competitive developer qualification and selection model. MISO prequalified 35 developers to bid on competitive transmission projects in 2014. This year, the RTO added 13 more developers.

Transource Energy, however, said that the changes to the selection process unreasonably grant MISO too much authority in transmission projects and their cost. The company said that under the revisions, MISO is allowed to unilaterally terminate developers' SDAs and force them to bear the costs. Transource also accused the RTO of ignoring its feedback in the stakeholder process.

Similarly, Xcel Energy said that some of the changes "inappropriately expand the role of MISO." For example, the company said, selected developers would be required to self-report any "potential violations" of federal or state law to MISO.

In a joint filing, International Transmission Co., Michigan Electric Transmission and ITC Midwest took issue with the requirement that developers submit projected revenue requirement information. This provision "could negatively impact an existing transmission owner's ability to submit competitive bids because two developers with the same estimated costs will calculate different revenue requirements if one developer already has [a] plant in service in MISO."

Little Rock-based Republic Transmission accused MISO of overlooking its duty to protect ratepayers in the interest of saving money for the RTO. The company said MISO ignored suggestions from stakeholders and provisions designed to cap or minimize the costs of projects in CAISO and PJM.

"MISO does not propose to 'improve' its developer selection process in a manner that protects MISO ratepayers by shifting its current minimal selection focus on cost to more heavily rely on the cost components of bids," asserted Republic Transmission in its protest filing. "Much work remains in MISO for ratepayers to benefit from Order No. 1000."

MISO seeks to implement the changes by Nov. 16, with the aim of posting its first competitive transmission project for bidding in January. Technically, MISO's compliance obligations to meet Order 1000 ended on March 31, but the RTO elected to keep working with transmission owners and non-incumbent developers to refine Tariff language and develop a binding selected developer agreement.

"These enhancements and clarifications reflect MISO's experience and discussions with stakeholders during the first year of the prequalification process as well as lessons learned from observing the processes of other RTOs," MISO said.

MISO's competitive transmission developer selection process has been the subject of four rounds of FERC compliance filings and, according to the RTO, 16 months of consultation with stakeholders. The RTO said it will make another compliance filing next month addressing other areas needing improvement.

SSR Unit's Recovery of Fixed Costs Upheld

By Amanda Durish Cook

FERC last week issued two orders reaffirming earlier rulings on MISO's disputed system support resource agreement with Illinois Power's Edwards Unit 1 generator in Peoria, Ill.

The SSR agreement took effect in January 2013 to keep the Edwards unit operating to address thermal and voltage problems until transmission upgrades can be completed in December 2016. Dynegy's Illinois Power unit acquired the plant from Ameren in December 2013.

In the first order, the commission affirmed its July 2014 finding that a generator should be allowed to recover its fixed costs through a full cost-of-service rate when it is forced to continue operating for reliability reasons (EL13-76-001, *et al.*).

MISO industrial customers and the PJM Market Monitor challenged the 2014 order, arguing that uneconomic generators targeted for retirement are not recovering their fixed costs from the market and should not receive a "windfall" because they are needed for reliability. (See *PJM IMM Questions MISO Cost Recovery Ruling*.)

The commission saw it differently. "Although a retiring generator may view undepreciated costs as being sunk and may write-off any loss at the time of retirement, the fact remains that MISO has the ability to unilaterally delay this decision," FERC said. "During this delay, an SSR unit owner is providing utility service, and … when a generator is required to provide utility service, it should be permitted to recover costs beyond going-forward costs."

Last week's order also affirmed the commission's earlier ruling that the Federal Power Act prevents the commission from providing retroactive cost-of-service recovery. The order left the commission's previous rulings regarding Edwards' 2013 and 2014 costs unchanged.

In the second order, FERC denied requests for rehearing of the commission's March 31 order that renewed Edwards' SSR agreement for one year through 2015 (ER15-943-002, *et al.*).

Hoosier Energy Rural Electric Cooperative, Illinois Municipal Electric Agency, Prairie Power, Southern Illinois Power Cooperative and Wabash Valley Power Association sought rehearing on the basis that MISO needed to conduct a new reliability analysis to re-evaluate the need for Edwards as an SSR unit. The companies contended MISO's 2013 analysis may be out-of-date. FERC agreed with MISO that there were "no significant changes" that would necessitate a new analysis.

MISO NEWS

FERC Rejects Complaints over MISO South Through-and-Out Tx Rules

By Amanda Durish Cook

FERC last week rejected two complaints alleging that MISO overcharged for through-and-out transmission on the MISO South system.

The nearly identical complaints originated from Morgan Stanley Capital Group and eight Entergy export customers, including several Southern Co. utilities and the Springfield, Mo.-based Associated Electric Cooperative Inc. (AECI). The complainants claimed that the power they received from Entergy's territory was overpriced, violating the grid operator's no-cost-sharing rule and section 206 of the Federal Power Act. They sought refunds from Dec. 19, 2013, when Entergy transferred control of its transmission facilities to MISO. The parties also asked for an investigation if FERC found improprieties.

FERC found that the through-and-out transaction rates did not violate MISO's Tariff because the no-cost-sharing-rule found in Tariff attachment FF-6 doesn't apply to through-and-out charges (EL15-66, EL15-77). The commission also decided the complaints were "duplicative" because the justness and reasonableness of the rates under section 206 is already being challenged by AECI (EL14-19).

That case opposes current through-and-out transmission rates under recent MISO Tariff revisions that provide a five-year transition period "governing regional allocation of network upgrades." MISO filed for the Tariff changes with FERC in mid-2013 after Entergy moved to MISO control.

"Commission precedent prohibits the filing of successive complaints that seek to relitigate the same issue absent new evidence or changed circumstances," FERC wrote.

The complaints said that since the MISO integration, the charges for long-term firm point-to-point transmission service have risen from an average of $1.78/kW-month to $3.45/kW-month.

In its complaint, Morgan Stanley said it was unjust for MISO to apply differing transmission rates to customers based on if they have a sink in or out of the RTO. The company said MISO's cost assessments are discriminatory because MISO is excluding "MISO Midwest costs from transmission rates charged to former Entergy customers that have a sink in MISO South but is not excluding such costs from former Entergy customers that sink outside of MISO South." The company also said that customers that sink in SPP are being treated differently than those that sink in PJM.

MISO said the complaints overlooked elimination of its pancaked rate as a result of Entergy's integration.

"MISO and Entergy state that the purpose of applying an average system-wide rate to through-and-out service is to treat all competitors for a specific load the same. In MISO's view, complainants are asking the commission to grant them a preferential rate not available to other similarly situated customers," MISO stated.

Planning Advisory Committee Briefs

MTEP 15 Moves Forward; Discussion on Revising MTEP Process Continues

The Planning Advisory Committee wrapped up stakeholders' review of the draft 2015 MISO Transmission Expansion Plan with a vote of support last week. The System Planning Committee will consider the plan in December.

MTEP15 contains about 352 transmission projects valued at a total of about $2.4 billion. (See *MISO Proposes $2.4 Billion in Transmission Projects*.)

The approval comes amid continuing stakeholder discussion on revamping the MTEP economic planning process.

Durgesh Manjure, MISO's manager of resource adequacy coordination, said the annual process typically begins in September and lasts until March or beyond. MISO has suggested a three-year cycle to replace the annual process and holding dedicated stakeholder workshops instead of setting MTEP planning as an agenda item. He said the reworking puts into question whether MISO should spend "six to nine months every year" of stakeholder time and energy devising the MTEP.

"There would be some work involved both on the MISO side and the stakeholder side," Manjure said of the changes, which would be implemented beginning with MTEP17. (See *MISO Planning Advisory Committee Briefs*.)

The committee proposes conducting a review at the beginning of an MTEP cycle to see if the economic and policy landscapes are still properly represented, then reusing unaffected futures information. The panel also favors reusing resource expansion and siting data in subsequent PROMOD models, while updating the transmission topology annually.

MISO to Provide Clean Power Plan Scenarios in Analysis

MISO officials are still at work providing an impact analysis on how states will be affected by the Clean Power Plan. States have until 2018 to finalize plans under the rule.

"It's necessary to start sooner than later because of long lead time on transmission projects," said Jordan Bakke, senior policy studies engineer at MISO, who provided the PAC with a CPP analysis.

Bakke has worked on developing modeling assumptions and futures definitions. Through mid-2016, MISO plans to model transmission futures and sensitivities, with consideration given to state plans. Bakke said the PAC will turn to states, stakeholders and experts for feedback.

In its analysis, MISO examined the effects of both a partial and an accelerated CPP rollout. The model for a partial CPP implementation projects a 17% reduction in emissions by 2030 from 2005 levels. An accelerated CPP implementation would bring a 43% reduction. The final CPP rule calls for a 32% reduction.

Continued on page 9

MISO News

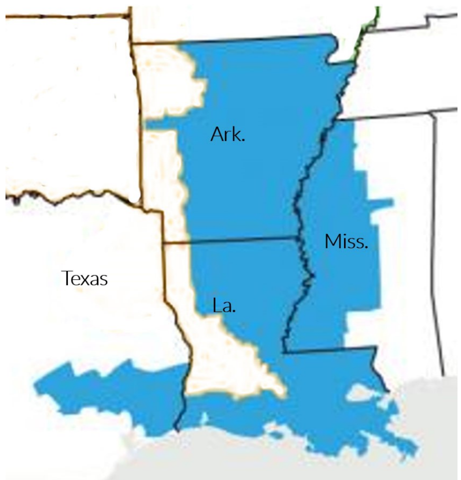
FERC Sets Hearings for Entergy's Cost Allocations, Rejects Rehearing Requests

By Tom Kleckner

FERC last week set Entergy Corp.'s ninth annual allocation of its operating companies' 2014 production costs for hearing and settlement procedures (ER15-1826).

As it has in years past, FERC said Entergy had not proven its proposed rates were just and reasonable. It accepted the proposed rates and made them effective June 1, 2015, subject to refund pending the hearing and settlement procedures.

The commission also issued three orders in long-running disputes regarding Entergy cost allocations for a portion of 2005, setting one issue for hearing and settlement procedures and rejecting two rehearing requests.



Entergy service area *Source: Entergy*

Bandwidth Remedy

At issue is how Entergy allocates production costs among its half dozen operating companies under its system agreement. The companies essentially operate as one system, although each has different operating costs.

Payments are made annually by low-cost operating companies to the highest-cost company in the system, using a "bandwidth" remedy that ensures no operating company has production costs more than 11% above or below the Entergy system average.

Regulators in Entergy's states have regularly challenged the annual bandwidth filings. Entergy's proposed rates for 2014 drew protests from the New Orleans City Council and the Louisiana and Texas commissions.

FERC gave the administrative law judge overseeing the case discretion to combine the proceeding with the previous four years of disputed annual cost-allocation cases, which were consolidated in December. (See *FERC Bundles Entergy 'Bandwidth' Disputes for Hearing*.)

2005 Calculations

The three other orders concern Entergy's first cost-allocation calculations, for a seven-month period in 2005.

It denied a request from the Arkansas commission to exclude Entergy Arkansas from making payments and an Entergy compliance filing for hearing and settlement procedures (EL01-88-013).

FERC had rejected a 2011 compliance filing because it used six months of data to recalculate the seven-month period. The company responded with a more comprehensive recalculation report it said were based on the actual books and records of each operating company.

The New Orleans City Council and the Arkansas and Louisiana commissions all protested. The Arkansas Public Service Commission argued the compliance filing should be rejected because it assumed Entergy Arkansas would make further bandwidth payments, even though the company had withdrawn from Entergy Corp.'s system agreement in December 2013.

FERC said that it had never indicated that Entergy Arkansas should be exempt from the bandwidth calculations for that period.

Interest Payments Required

The commission also rejected the Arkansas commission's argument that the bandwidth payments — $167.3 million, plus $56.5 million in compounded interest — amounted to "exit fees," saying the payments were "obligations specifically required by the system agreement and are for a period when Entergy Arkansas was subject to the system agreement."

(FERC Commissioner Colette Honorable, a former member of the Arkansas PSC, did not participate in the order.)

The commission also denied Entergy's request for rehearing of an earlier order rejecting a compliance filing (EL01-88-012) and one issued in response to a ruling by the D.C. Circuit Court of Appeals (EL01-88-011), ordering Entergy to include interest on recalculated bandwidth payment amounts from the seven-month period.

FERC disagreed with Entergy's contention in the compliance-filing request that the commission had failed to adequately explain its decision to require interest. Interest, the commission said, ensures that "the recipient receives payment in inflation-adjusted dollars."

Planning Advisory Committee Briefs

Continued from page 8

"There are so many options available for states … that we really need to provide more certainty," Bakke said.

The second round of stakeholder feedback included requesting detailed models of Environmental Protection Agency compliance options using both rate- and mass-based emission limits, allowances, set-asides, interstate trading and treatment of leakage. Stakeholders also asked that MISO re-evaluate the level of plant retirements, energy efficiency and penetration of solar and wind resources in the findings.

"We want as much feedback as possible. This is a very complex issue, and we don't want to make stuff up," Bakke said.

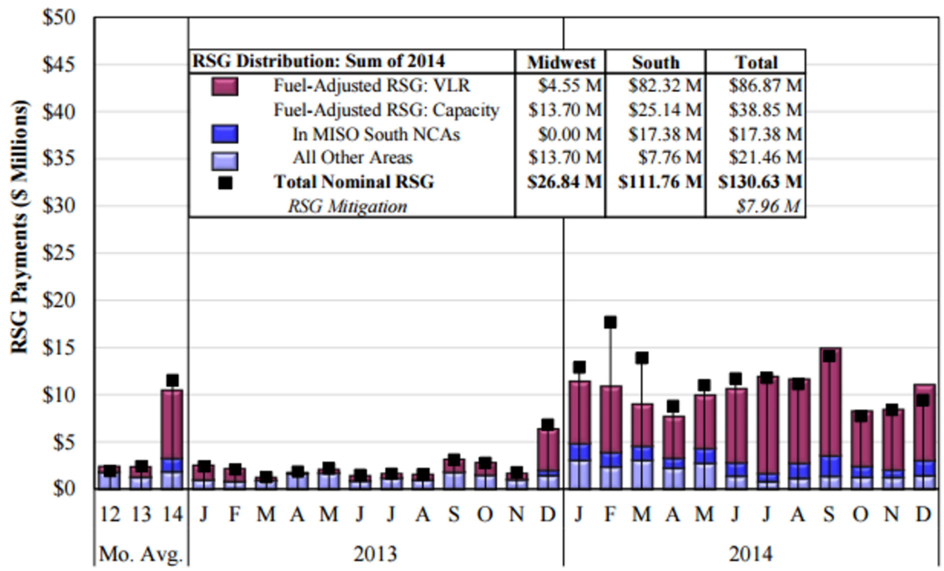
A final scope of study will be revealed at November's PAC meeting.

— Amanda Durish Cook

MISO News

FERC: More Transparency Needed on Cost Allocation for Voltage Fixes

By Amanda Durish Cook



Day-ahead revenue sufficiency guarantee payments, 2013-2014. *Source: Potomac Economics*

FERC last week approved a MISO compliance filing regarding its cost allocation method for resources committed for voltage or local reliability (VLR) requirements but required the RTO to make its study process on "commercially significant" voltage problems more transparent (ER12-678-005).

"Although we find that MISO has complied with most of the directives in the June 2014 order, we agree with the protesters that MISO did not adequately comply with other directives; as a result, the Tariff needs further clarification," FERC wrote.

The ruling originates from two filings MISO made in December 2011. One proposed that the local balancing authority (LBA) area shoulder more of the costs resulting from VLR requirements. The second proposed a mechanism to mitigate the ability of resources needed for voltage support to exercise market power. After holding a technical conference, FERC conditionally accepted the proposals.

In a June 30, 2014, order, the commission put limits on the discretion of transmission owners to determine if a VLR commitment is commercially significant and put more emphasis on stakeholder participation in the determination.

The determination of whether a VLR issue is commercially significant is based on the frequency of occurrence and monetary impact. The costs of those judged commercially significant are spread more broadly among LBAs than those determined to be local.

NRG, TDUs Complain

NRG Energy and four transmission-dependent utilities — Midwest Madison Gas and Electric, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services and WPPI Energy — protested last year's compliance filing, saying MISO should be required to conduct regular meetings with stakeholders and share information used to perform studies.

The commission rejected on procedural grounds NRG's request that MISO be required to provide the study model. But it agreed with the complainants that MISO had not done enough to make the study process open and transparent.

"We agree with Midwest TDUs that language added by MISO in the compliance filing … would limit the participation in the study process of local BAAs and interested market participants to merely requesting a study. If these requests will be rolled into the quarterly study process that MISO would normally do anyway, it is unclear how MISO's additional language would provide an open and transparent study process," the commission said.

It ordered MISO to add new language permitting LBAs and market participants to participate in the studies and request that reoccurring VLR commitments be studied.

It also directed the RTO to hold regular meetings with stakeholders similar to those conducted when identifying system support resources under the Tariff, saying it "will provide more meaningful participation and opportunity to provide feedback."

"With regard to a market participant's access to data during the study process, we agree with Midwest TDUs that MISO's proposal to limit access to such data to those parties that request the study has not been shown to be in compliance with the June 2014 order," FERC continued.

It required MISO to provide all the assumptions and outputs of the model to any party that is liable for VLR-related charges that signs a non-disclosure agreement.

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NYISO NEWS

Net Metering Caps Temporarily Lifted in New York

By William Opalka

The New York Public Service Commission on Thursday temporarily lifted caps on the amount of net-metered solar energy that can be permitted on a utility system. The move was prompted by a July petition from Orange and Rockland Utilities seeking to suspend its net-metered installations because it had applications for interconnections that exceeded the limit it can accommodate under current state rules.

While the petition came from ORU, the commission ruled that all six investor-owned utilities in New York must file tariff revisions to the rules governing their net-metering caps by Oct. 30, which will become effective Nov. 6.

Under the state's 6% cap, ORU said it would reach its 62-MW limit in the "near future" and should immediately be allowed to suspend interconnections at that time.

The commission, however, rejected ORU's proposal for a "buy-all, sell-all" solution whereby a distributed-generation customer would sell all its generation output at a wholesale rate and purchase all the electricity it needs at the retail rate.

The PSC said the ceiling would float upward to accommodate all new applications until the commission can answer a key question: How much are distributed energy resources worth? That answer is expected by the end of next year, under New York's Reforming the Energy Vision initiative (15-E-0407).

"Rather than engaging in another effort to arrive at the proper level of the ceiling that would anticipate perfect coordination with the implementation of REV, the ceilings shall be allowed to float in the interim until the calculation ... affecting valuation of DER is decided," the commission wrote. "That is, utilities shall accept all interconnection applications and continue to interconnect net metered generation without measuring the DG capacity against an artificially set ceiling level."

The order said state law gave the commission discretion to adjust the caps in the current scenario. It also said momentum to attain the state's clean energy goals need not be interrupted now. "The pace of development should be set by the NY-Sun program and other policies for promoting net metered generation, not by the level of the ceilings," the order said. NY-Sun is Gov. Andrew Cuomo's effort to spend $1 billion by 2023 to install 3 GW of solar generation.

Much of the commission's discussion centered on whether lifting the cap may create a "gold rush" for residents who want to install rooftop solar.

To Commissioner Diane Burman, who opposed the move, the interim approach will entice potential customers to rush into the interconnection queue to reserve a place and be grandfathered into the system at the time the PSC determines what the cap ultimately should be.

"I don't see what we're doing today as helpful over the long term," she said.

Commission Chair Audrey Zibelman said setting a higher hard cap now would have a similar negative effect, with residents hurrying to reserve a place in the queue before they are cut off when a utility's limit is reached, creating a stop-and-go scenario for the industry.

"We have a burgeoning solar industry, and we must not allow the caps to become a barrier," she said.

This is the second time in less than a year the commission has had to address the cap when a utility approached its limit. Last December the commission doubled the statewide cap from 3% to 6% when environmentalists and Central Hudson Gas & Electric petitioned regulators for an increase. (See *New York Doubles Solar Net Metering Cap to 6%*.)

New York Sees Winter Prices Moderating

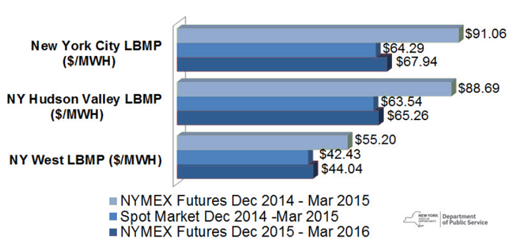
By William Opalka

New York's winter electricity prices are expected to average about 9% lower than last year's, the staff of the New York Public Service Commission said on Thursday.

In a presentation to the commission, staffers said market conditions would benefit from better preparation and other practices refined over the past two winters, as well as from lower natural gas prices that have also influenced other eastern U.S. markets.

"We have adequate resources to meet the needs of the utilities ... while we're also looking at lower commodity prices," said Raj Addepalli, managing director for utility rates and services at the PSC.

For example, at the New York Mercantile Exchange, futures prices for electricity in the New York City, Hudson Valley and Western New York zones range from about $11 to $23/MWh lower than they were a year ago. New York City futures prices averaged $91.06/MWh a year ago, while that same contract now averages $67.94.



Source: NYPSC

The PSC said utilities and the commission have instituted a series of "lessons learned" procedures that grew out of the polar vortex two years ago. Plants have increased their capacity for on-site fuel storage, especially in eastern New York, and state officials have implemented an expedited procedure to obtain permits from the Department of Environmental Conservation to allow fuel-oil burning.

NYISO Provided Data	MW
2015 Generation	40,938
New York Special Case Resources (SCRs)	885
External Purchase Contracts	338
LESS: Total Projected Capacity Outages	(6,238)
TOTAL 2015 CAPACITY	**35,922**
Load Forecast	24,515
Operating Reserve Requirement	2,620
Capacity Margin	8,787

New York winter 2015/16 capacity and load.
Source: NYPSC

NYISO NEWS

Renewable Energy Reporting Sparks Privacy Concerns in New York

By William Opalka

Market participants in New York are concerned that their proprietary information might not be adequately protected as NYISO plans to bring the RTO's reporting system for renewable energy generation into compliance with state law.

The New York State Energy Research and Development Authority (NYSERDA), which procures clean energy, was required by a 2012 law to develop the Generating Attribute Tracking System to ensure compliance with the state's renewable portfolio standard.

Generators' representatives raised concerns Wednesday when the NYISO Business Issues Committee discussed a proposed change in the ISO's code of conduct that states the information would be confidential and that market participants will be notified of any requests for confidential data or any decision to disclose it.

The discussion came as New York Assemblyman James Brennan is petitioning the Public Service Commission to force disclosure of bidding information from power generators that they say is proprietary and threatens to disrupt the market if not protected. The PSC and the secretary of the state's Department of Public Service last year dismissed a similar request under the state's Freedom of Information Law. (See *NYPSC Chair Zibelman Acknowledges Costs Concerns*.)

Market participants fear that if the proprietary information from the traditional generators is disclosed, by either the PSC or by the courts following any legal action that the assemblyman may initiate, GATS information would be released as well.

"There's a lot of concern about the release of information that everybody agrees is confidential," said Howard Fromer, who represents PSEG Long Island.

NYISO would provide data on megawatts produced and consumed and on import and export transactions. No financial data on settlements and revenue would be included.

No trading is available in the self-contained New York renewable energy market, which officials said Gov. Andrew Cuomo wants to change. Renewable energy certificates (RECs) are traded in the neighboring jurisdictions of ISO-NE and PJM.

NYISO is negotiating an agreement with NYSERDA's vendor, APX, which will keep data confidential except for identified purposes, NYISO said. APX runs several REC registries, including those in Michigan, North Carolina and New England.

Peter Keane, NYSERDA's deputy general counsel, said that since the New York portfolio standard was set in 2004, only one request for private information has been made. That involved a dispute over lease payments between a property owner and the owner of wind turbines at the owner's site. The dispute was resolved before a decision had to be made on the release of the information.

The proposed code of conduct change moves to the ISO's Management Committee at the end of the month. GATS is expected to be publicly available in March.

FERC Again Rejects Price Suppression Argument in Ginna Dispute

FERC ruled on Thursday for the third time that an allegation of "price suppression" in the capacity market was outside of the scope of an ongoing proceeding to review a proposed agreement to prop up the struggling R.E. Ginna nuclear power plant in New York (ER15-1047).

FERC rejected TC Ravenswood's request for rehearing of a previous order that granted rehearing for other aspects of the Ginna proceeding. TC Ravenswood had argued that FERC had incorrectly determined the reliability support services agreement's effects on the capacity market were not relevant. (See *NYPSC Approves 5.2% Ginna Rate Surcharge*.)

Because the rehearing order reaffirmed FERC's stance on the price suppression issue in its original order on Ginna, "we find that TC Ravenswood's request for rehearing is improper and we will dismiss it," the commission said.

— William Opalka

PJM NEWS

Board Welcomes Ott into New Role as CEO

Boston Feted at OPSI Meeting

By Suzanne Herel

Ott

Andy Ott is officially head of PJM, after spending a six-month transition period at the side of retiring CEO Terry Boston.

Boston will serve as CEO emeritus until his retirement Dec. 31 after eight years at the helm.

The PJM Board of Managers welcomed Ott into his new position as president and CEO at its meeting last week.

"Terry Boston's service to PJM and stakeholders has set a high standard," board Chairman Howard Schneider said. "The board and I are confident that Andy will continue to ensure the stakeholder collaboration and outstanding performance for which PJM is known while establishing his own visionary leadership."

Since being named Boston's successor in April, Ott has been meeting with PJM stakeholders, including members, state and federal regulators, employees and industry leaders, the RTO said in a release. (See Incoming PJM CEO Ott Expects Challenges from an Industry in Transition.)

"The smooth and successful transition has resulted in this being the right time for Andy to take the helm," Schneider said.

Praise for Boston

Boston was feted at the Organization of PJM States Inc. annual meeting in Baltimore last week.

"There's a lot of things that make Terry exceptional, not the least his humility," said FERC Commissioner Cheryl LaFleur, a luncheon speaker at the event Monday. "He has a rare combination of technical expertise — no matter what you're talking about: everything from transformers to transmission planning to market planning — and people leadership skills."

Boston was presented with a plaque and a standing ovation the following day. "I could not have picked a better place to end my career than PJM," said Boston, who joined PJM from the Tennessee Valley Authority. (See Retiring PJM CEO Boston Lauded for Efficiency Improvements, Management Style.)

Ott's Experience

Ott's previous role was as PJM's executive vice president of markets. An 18-year veteran with the RTO, Ott was responsible for implementing LMP, financial transmission rights, the day-ahead energy market and capacity market.

Prior to joining PJM, he worked for GPU Inc. in transmission planning and operations.

He is a board member of both PJM Technologies and PJM Environmental Information Services. He also serves on the board of directors for the Association of Power Exchanges and chairs the Study Committee on Electricity Markets and Regulation for Paris-based CIGRE (International Council on Large Electric Systems).

He received his bachelor's degree in electrical engineering from Pennsylvania State University and his master's in applied statistics from Villanova University. Ott is an Institute of Electrical and Electronics Engineers fellow.

Rich Heidorn Jr. contributed to this article.

PJM Suggests Changes to Virtual Transactions

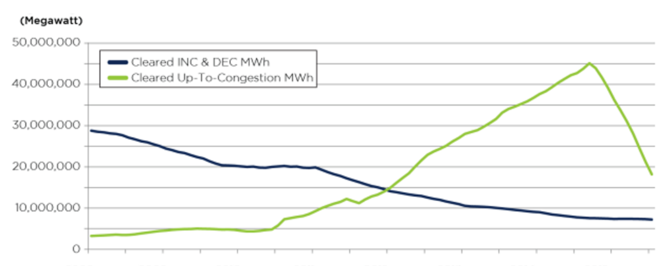
By Suzanne Herel

PJM recommended three market rule changes regarding virtual trading in a report requested by stakeholders and released last week.

"The goals of these proposed rule changes are to maintain the benefits added to PJM's markets by virtual trading, eliminate opportunities for inefficient trades to profit in the market and level the allocation of uplift across all virtual transactions," the report said. (See PJM Ponders Changes to Virtual Trades, DA Market.)

It recommends:

- Aligning the eligible trading points for increment offers (INCs) and decrement bids (DECs) with nodes where generation, load or interchange transactions are settled, or at trading hubs;
- Altering the biddable locations for up-to-congestion transactions (UTCs) to generation buses as sources only, trading hubs, load zones and interfaces; and
- Allocating uplift to UTCs consistent with INC and DEC transactions.



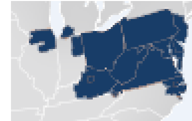
Cleared virtual transactions (12-month rolling average) *Source: PJM*

PJM said it proposed the changes to stimulate stakeholder discussion. "The goal of this discussion is to retain all of the positive aspects that virtual transactions bring to the market while removing the bulk of the issues that they can create when used inefficiently under the existing rules."

An overview of the report will be presented at the Oct. 22 meeting of the Markets and Reliability Committee. The study also looks at the purpose of virtual trading, the mechanics by which such trades are offered and cleared, potential problems that can arise and examples of how market participants use them.

Virtual transactions have been incorporated in PJM energy markets since the June 1, 2000, inception of the day-ahead market. They are bids and offers that take financial positions without the intent of delivering or consuming actual power in the real-time market.

PJM NEWS



FERC Upholds Capacity Market Parameters

By Suzanne Herel

FERC last week upheld its Nov. 28 order accepting PJM's changes to its capacity auction demand curve and related parameters, denying rehearing requests by a broad group of interests (ER14-2940).

PJM said the changes to the variable resource requirement (VRR) curve and related pricing inputs, including the cost of new entry (CONE), were identified in the RTO's triennial review as being necessary to meet evolving market conditions.

The new, more conservative curve results in the procurement of more capacity and carries an estimated 1% cost increase (about $216 million).

PJM uses the curve to gauge how much capacity it needs to meet the one-in-10-year loss-of-load standard. A lower-cost VRR curve identified by The Brattle Group, the independent consultant that conducted the study, would fail to meet the needs of a one-in-five-year event 13% of the time, PJM said.

In the November order, the commission agreed with PJM that the changes to the VRR curve were needed to ensure reliability "in light of evolving market conditions and anticipated supply shifts," including the planned retirement of 26,000 MW of coal-fired generation. The order accepted the explanation of PJM's expert witness, economist Paul M. Sotkiewicz, who argued that, due to the anticipated changes, PJM's prior modeling assumptions were no longer appropriate.

A coalition comprised of the Maryland Public Service Commission, the New Jersey Board of Utilities and PJM load-serving entities challenged PJM's assessment of evolving market conditions, saying that most of the coal retirements have already occurred and that the region has added 17,000 MW of natural gas-fired capacity in the last three years.

The commission rejected the challenge, saying that its acceptance of the new VRR curve "was not based on the specific timing of these retirements, but on the inability of PJM's prior modeling construct to capture these evolving conditions and thus on the resulting need for a more conservative VRR curve."

The PJM Power Providers Group (P3) and Public Service Enterprise Group disputed PJM's use of an 8% cost of capital used in CONE calculations, saying it was too low because it relied on corporate-level data for publicly traded independent power producers and did not reflect riskier, project-level financing. (See *PJM Generators Seek Support for Capital Boost*.)

The commission said that in addition to IPP data, it also relied on market- and transaction-based cost of capital data.

"This evidence was verifiable and reflects the market's required compensation for the specific, systemic operating risks attributable to merchant generation, and the willingness of borrowers to bear these risks," the commission said.

FERC won't Rehear MOPR Ruling

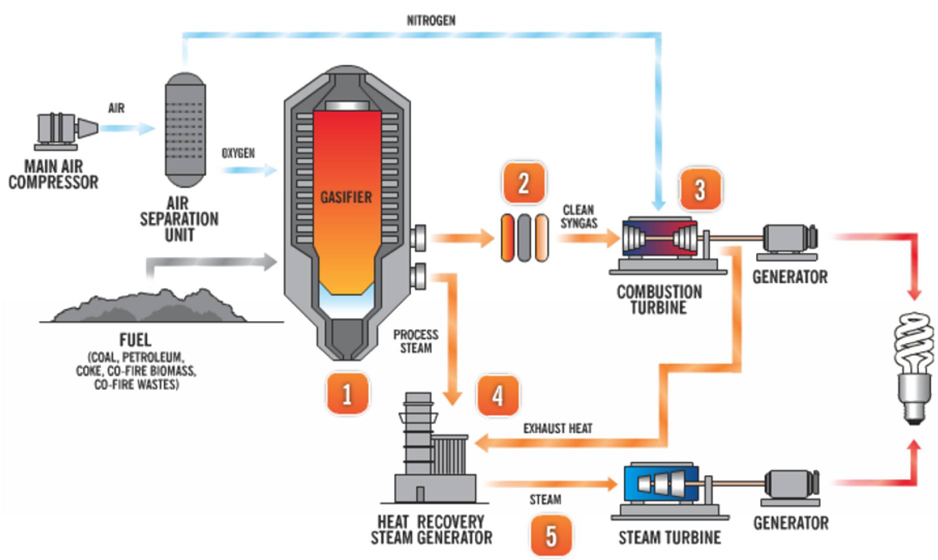
By Suzanne Herel

FERC declined last week to rehear a 2013 order approving PJM's revisions to a rule designed to mitigate buyer-side market power in the capacity market.

The ruling addressed the minimum offer price rule (MOPR), which PJM added to its auction protocols in 2006 amid concern that load could have an incentive to suppress market clearing prices by offering supply at less than a competitive level (ER13-535). (See *Split Decision on MOPR; FERC Upholds PJM Exemptions, Rejects End to Unit-Specific Review*.)

PJM in 2013 proposed narrowing the list of resource types to which MOPR would apply, eliminating the unit-specific review process and establishing categorical exemptions for competitive entry and self-supply resources.

That, PJM said, would create a better defined and transparent process for granting MOPR exceptions, while addressing concerns from market participants about competitiveness in the 2012 capacity market auction.



IGCC process *Source: Duke*

FERC accepted the exemptions but ordered that PJM retain its unit-specific review process.

The order was challenged by stakeholders including NRG Energy, state consumer advocates, the PJM Power Providers Group (P3), the Illinois Commerce Commission, Calpine and FirstEnergy.

Continued on page 15

PJM NEWS

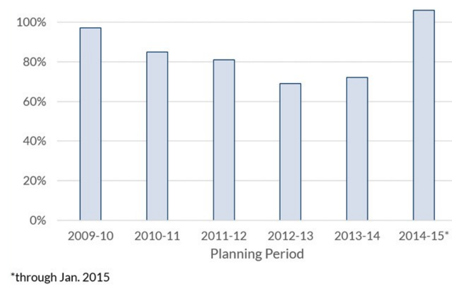
PJM to File FTR, ARR Rule Changes with FERC

By Suzanne Herel

The PJM Board of Managers last week directed staff to seek FERC approval for a package of rule changes related to financial transmission rights (FTRs) and auction revenue rights (ARRs) after the Members Committee nearly reached consensus on the proposal.

"In making this decision, the board took into account the near two-thirds consensus achieved through the stakeholder process," PJM said in a release. "It also considered the need to address the equity issues associated with the current rules by which the transmission system is planned to ensure future feasibility of Stage 1A ARRs and revenue inadequacy is allocated among holders of both positively and negatively valued FTRs."

The RTO said the filing would be made shortly, and FERC would be asked to take action by the end of the year to provide adequate notice prior to the 2016 annual ARR allocation and FTR auction.



FTR revenue adequacy *Source: PJM*

The rules changes, proposed by Old Dominion Electric Cooperative, would redesign the FTR and ARR processes, combining recommendations from PJM and the Independent Market Monitor.

In August, the MC fell just short of a sector-weighted consensus on the proposal, which was backed by most members of the End Use Customer, Transmission Owner and Electric Distributor sectors but won support of only one-third of the Generation Owner and Other Supplier sectors. (See ODEC Seeks Last-Ditch Vote on Deadlocked FTR/ARR Issue.)

The plan contains three elements.

One, drawn from a PJM staff proposal regarding the Stage 1A 10-year process, escalates the current ARR results using a zonal load forecast growth rate of +1.5%. The other two elements change the method of reporting the monthly payout ratio so that any negative target allocations are included as revenue, slightly increasing the reported payout ratio. It also treats each FTR individually, eliminating the netting of positively and negatively valued FTR positions in a portfolio prior to determining positively valued FTR payout ratios.

FERC Won't Rehear MOPR Ruling

Continued from page 14

'Flawed' Process

Calpine said FERC was mistaken in requiring PJM to retain the unit-specific review because the commission had acknowledged in the 2013 order that it was "flawed." FERC said it had acknowledged that the process "warranted additional stakeholder review and the consideration of certain enhancements."

Nevertheless, it said "we cannot conclude, based on the record before us, that review of individual units' costs and revenues is an unjust and unreasonable method of determining rates. To the contrary, the commission noted in the May 2013 order that, based on PJM's assessment, the clearing prices in PJM's capacity auctions held during the period in which the unit-specific review process has been in effect have been just and reasonable."

Exemption for IGCC Units?

The ICC said FERC erred in allowing PJM to subject integrated gasification combined-cycle generators to the MOPR because they require long development times and thus incur significant sunk costs prior to their participation in capacity auctions, making them unlikely to suppress capacity prices.

The commission responded by citing PJM's "concerns regarding the ability to eliminate the gasification component of an IGCC plant such that the project originally planned as an IGCC plant could become a combined-cycle plant."

"Based on these concerns, we continue to find the relevant characteristics of an IGCC resource justify their inclusion in the MOPR, consistent with PJM's treatment of other natural gas-fired units," FERC said.

Discrimination Against Competitive States Alleged

The commission also rejected a complaint by consumer advocates that the MOPR is discriminatory because generation in restructured states is not eligible for the self-supply exemption and because the competitive entry exemption qualification requirements are more stringent than those for self-supply in traditionally regulated states.

The commission accepted PJM's proposal to exempt new entry projects developed through a state-sponsored or mandated procurement process as long as that process was competitive and non-discriminatory. FERC gave no ground in its new order, saying the differences between the eligibility requirements for the competitive entry and self-supply exemptions were not discriminatory.

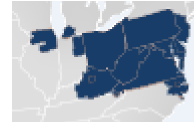
"Both the competitive entry and self-supply exemptions are tailored to ensure that merchant resources that have no incentive to artificially suppress capacity prices are able to offer into the capacity auction at prices that are not subject to mitigation," it said.

Self-Supply Concerns

FirstEnergy worried that the self-supply exemption could be gamed. NRG argued that the self-supply exemption "will result in a large number of new power plants being built by vertically integrated utilities and public power entities, the effects of which will suppress market clearing prices."

"We disagree," the commission responded. "With properly calibrated [net short and net long] thresholds, PJM's self-supply exemption will not operate in a manner that encourages uneconomic entry and thus will not artificially suppress market clearing prices."

PJM NEWS



MRC/MC Preview

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

RTO Insider will be in Wilmington, Del., covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

3. PJM MANUALS (9:25-9:35)

Members will be asked to endorse the following manual change:

- Manual 14B: PJM Region Transmission Planning Process. Establishes criteria for reliability studies focused on meeting winter peaks from Dec. 1 through Feb. 28. Includes assumptions for the input power flow models and parameters for the analytical studies to be performed. (See "Winter Study Criteria, Uplift Added to Planning Manual," in *PJM Planning Committee Briefs*.)

4. TIER 1 COMPENSATION (9:35-9:55)

The committee will be asked to approve manual and Tariff language changing compensation of Tier 1 synchronized reserves. Under the new scheme, Tier 1 synchronized reserve resources will be obligated to respond in emergencies and subject to penalties if they can't. It retains Tier 1's ability to receive compensation outside of synch reserve events when the non-synch reserve market price is more than $0. Units could opt out of the performance obligation, but by doing so they would forfeit any credit they would have received outside of responding to an event. The changes will go before the MC on Nov. 19 and would be implemented no earlier than February. (See "Tier 1 Compensation Language Approved," *PJM Market Implementation Committee Briefs*.)

5. REGULATION PERFORMANCE IMPACTS (9:55-10:10)

The committee will be asked to endorse revisions to Manual 11: Energy & Ancillary Services Markets Operations implementing changes to reduce over-procurement of RegD resources. The solution would move the benefits factor curve to the left so that it is at zero at 40%. A cap of 26.2% also would be implemented during identified excursion hours — hours when dispatch frequently moves the regulation signal manually. It also features tie-breaker logic to rank RegD self-schedules or zero-cost offers. (See "Solution, Task Force Proposed to Curtail RegD Resources," in *PJM Markets and Reliability Committee Briefs*.)

6. REGULATION MARKET ISSUES SENIOR TASK FORCE (10:10-10:20)

Members will be asked to endorse a draft charter for the Regulation Market Issues Senior Task Force. The task force will be tasked with addressing modeling problems that are causing PJM's regulation market to purchase too much RegD megawatts at times. (See agenda item 5 above.)

7. INCREMENTAL AUCTION TARIFF CLEAN UP (10:20-10:30)

A Tariff provision up for endorsement would allow PJM to release Base Capacity resources to reflect the Capacity Performance resources it acquired in the transition auctions for the 2016/17 and 2017/18 delivery years. (See "PJM Seeks Tariff Change to Release Excess Capacity," in *PJM Markets and Reliability Committee Briefs*.)

8. 2015 IRM STUDY RESULTS (10:30-10:45)

The results of the 2015 installed reserve margin study will be presented for endorsement. It increases the IRM for delivery year 2016/17 to 16.4% from 15.5% in the 2014 study. IRMs also rose for 2017/18 and 2018/19. (See "IRM, FPR Rising; PJM Methodology Challenged," *PJM Planning Committee Briefs*.)

9. GOVERNING DOCUMENTS ENHANCEMENT AND CLARIFICATION SUBCOMMITTEE (10:45-10:55)

The committee will be asked to approve a draft charter for the Governing Documents Enhancement and Clarification Subcommittee, which will be tasked with identifying, reviewing and resolving inconsistencies among PJM's governing documents and manuals. It also will offer revisions to correct ambiguous or confusing language.

Members Committee

ENDORSEMENTS (1:25-2:00)

1. CONSUMER ADVOCATES OF PJM STATES (1:25-1:55)

Members will be asked to vote on a proposal to fund a $450,000 budget for the nonprofit Consumer Advocates for the PJM States through an assessment on electric customers. It would amount to about 0.8 cents annually for a residential customer using 12,000 kWh. (See *Consumer Advocates' Funding Request Sparks Sharp Words*.)

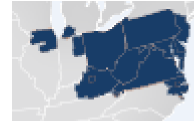
2. ELECTIONS (1:55-2:00)

Members will be elected for the Nominating Committee for 2015-16. The sector representatives are:

- Electric Distribution Sector: Lisa McAllister, American Municipal Power
- End Use Customer Sector: Ruth Ann Price, Division of the Public Advocate of the State of Delaware
- Generation Owner: Joe Kerecman, Calpine
- Other Supplier Sector: Marji Philips, Direct Energy
- Transmission Owner Sector: John Horstmann, Dayton Power & Light

— Suzanne Herel

PJM NEWS



FERC Rejects Refund on Polar Vortex Charges

By Suzanne Herel

FERC last week denied Champion Energy Marketing's request for a $3.1 million refund in PJM uplift charges related to the polar vortex of January 2014 (EL15-46).

Texas-based Champion, a load-serving entity, paid about $3.8 million in real-time balancing operating reserve (BOR) charges that it said it should not have been assessed because it had covered nearly 100% of its load for that month through forward contracts. Champion requested a refund of $3.1 million plus interest. The retail energy provider, a Calpine company, operates in Illinois, Pennsylvania, Ohio, New Jersey and Maryland in PJM.

It also asked that Tariff provisions governing BOR charges and allocations be amended, saying they were unjust and unreasonable "because it allocates BOR costs for reliability to all load when these costs should be allocated to market participants that were short supply."

The commission disagreed. "Despite the fact that Champion was long on an aggregate daily basis, as a load-serving entity with real-time load, Champion participates with other customers as part of an integrated grid and therefore relies on PJM to assure that its transactions can be delivered as scheduled," it said.

Commissioner Philip Moeller dissented in part. "Allowing PJM's current BOR cost allocation to continue harms market participants like Champion and decreases the efficiency of PJM's markets. Allocating costs broadly to load-serving entities like Champion unfairly frustrates their efforts to hedge their positions; it does not ensure that the market participants who actually caused those uplift costs pay corresponding charges.

"The fact that Champion benefits from grid reliability does not indicate that their actions caused the uplift costs it was forced to bear," he continued. "Champion and other load-serving entities should only be allocated uplift costs on the basis of those benefits when the parties who caused those costs cannot be identified."

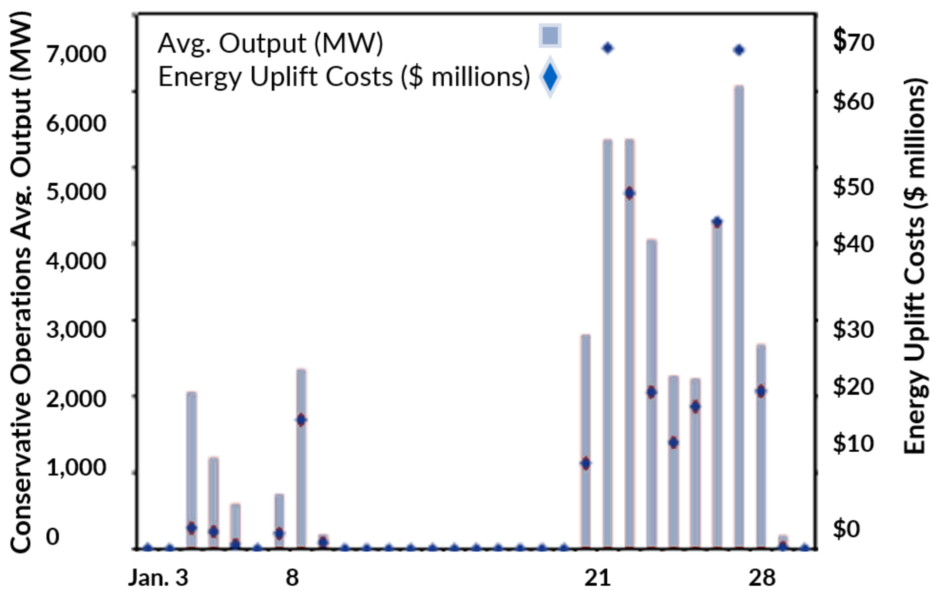
PJM said its operators responded appropriately to the extreme weather conditions and accompanying outages and that Champion's charges were consistent with the Tariff and how other LSEs were assessed.

It did note that Champion was allocated $2.8 million in real-time BOR reliability charges in January 2014 incurred as a result of actions taken by PJM's operators during the operating day that were "uneconomic but nonetheless needed to maintain the reliability of the PJM transmission system because physical, real-time load benefitted from the reliability provided by these operator decisions."

Uplift payments for all of 2014 totaled $964.7 million, according to the Independent Market Monitor's State of the Market report.

PJM acknowledged there was room for improvement in reducing uplift but pointed out that it was able to capture 98.1% of all system operating costs in 2014, leaving only 1.9% for BOR charges.

The Independent Market Monitor agreed that Champion's request should be denied but said the company did have a legitimate grievance that indicated the need for further reform of capacity market rules.



Average output for conservative operations, uplift costs (January 2014) *Source: 2014 State of the Market Report, Marketing Analytics*

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SPP NEWS

Members Discuss Revenue Distribution from MISO Settlement

By Tom Kleckner

LITTLE ROCK, Ark. — SPP's Markets and Operations Policy Committee began discussions last week on how the RTO will distribute the funds it receives from MISO under the settlement in their long-running transmission dispute, announced just hours before its meeting.

MISO will pay SPP and six independent transmission owners $16 million to settle all claims of compensation from Jan. 29, 2014, to Jan. 31, 2016. SPP will receive 60% of the total, while the remaining 40% will be disbursed to the independent transmission owners. (See related story, *SPP, MISO Reach Deal to End Transmission Dispute*, p.1)

David Kelley, SPP's director of interregional relations, said that because the funds are not being collected under the Tariff, SPP will have to make a filing with FERC setting rules for its portion's distribution to its members. Kelley said staff and parties to the settlement have determined that the payments should flow through to the benefit of SPP load.


Kelley

"The money could start flowing in March 2016," Kelley said. "We've had some conversations with members as a part of the settlement process, but we don't have any provisions set up yet."

Kelley said the majority of SPP transmission-owning members that were part of the settlement negotiations favor a 100% flow-based approach. Some stakeholders disagreed, suggesting a 100% load-ratio share approach or a 50-50 annual transmission revenue requirement/flow-based approach.

"We're all in this together when it comes time to build transmission, but we seem to lose sight of that when it comes time to distribute the revenue," said Dennis Florom of Lincoln Electric System.

Kelley said the general consensus is to develop a new settlement-specific Tariff schedule addressing revenue distribution. It would include a requirement that revenue be credited to benefit all customers taking SPP transmission service in the same manner in which point-to-point revenue is credited.

"We thought the revenues should be distributed on the same basis the service was granted," Kelley said. "But this is a conversation we needed to have."

He added, "I would not want to diminish what I think is a very significant victory."

South Central MCN's Noman Williams, chair of the MOPC, agreed.

"Let's not lose sight of this victory by squabbling over who gets the dollars," he said. "It all goes to the customers."

Task Force Debates Clean Power Plan Compliance

By Tom Kleckner

LITTLE ROCK, Ark. — SPP and its stakeholders began trying to put their arms around the massive task of Clean Power Plan compliance last week, debating the pros and cons of mass-based versus rate-based compliance, a reliability safety valve and how best to involve themselves in the compliance process.

The goals of SPP's Clean Power Plan Review Task Force — a name so unwieldy its chairman repeated it slowly to avoid stumbling over the words — are to develop policies and recommendations to SPP's Strategic Planning Committee, including the development of educational materials for environmental agencies and SPP's members and Regional State Committee. The task force will also provide comments to the Environmental Protection Agency on its Federal Implementation Plan, which the agency would apply to the states that fail to file their own plans by the 2018 deadline.

Rate vs. Mass

The task force delved into a recent staff survey of members that asked whether they preferred a rate-based or mass-based compliance approach, along with the pros and cons of each. Twelve of the 20 respondents said they preferred a mass-based approach or identified its advantages, with only one preferring a rate-based approach.

SPP Vice President of Engineering Lanny Nickell said the survey identified two ideas that have a broad consensus: 1) a robust emission-trading program is "paramount" no matter which compliance approach a state chooses; and 2) states should develop their own implementation plans, rather than be subject to the FIP, which will have less flexibility.

Those who indicated they favored the mass-based approach said it was due to its flexibility in accommodating various generation technologies, its ease of monitoring and its consistency with other current emission-compliance approaches and mechanisms.

Other comments in favor of a mass-based approach said it would likely lead to a more robust allowance trading program, and that trading between mass-based states could be accomplished using established criteria from similar programs. Emission-allowance prices would be more easily reflected in wholesale energy prices than emission rate credits, they said.

"The survey was good," Nickell said. It "at least gave us a preliminary feel."

Nickell, who is leading the RTO's CPP compliance efforts, said a trading-ready approach is gaining favor as a way to reach compliance.

"But if a few states go one way and the rest go the other way, those few states may have trouble trading," he said. "It's my understanding they're not compatible. If you have a rate-based state, you can't trade with a mass-based state."

Reliability Still a Concern

SPP staff also shared a qualitative assessment of the proposed FIP, with Director of System Operations Sam Ellis pointing out that EPA will consider comments about providing for a reliability safety valve for mass-based plans. For example, he said the proposed FIP does not factor generating units' need to run for reliability reasons

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SPP News

Markets and Operations Policy Committee Briefs

Lone Interregional Project Faces Hurdles

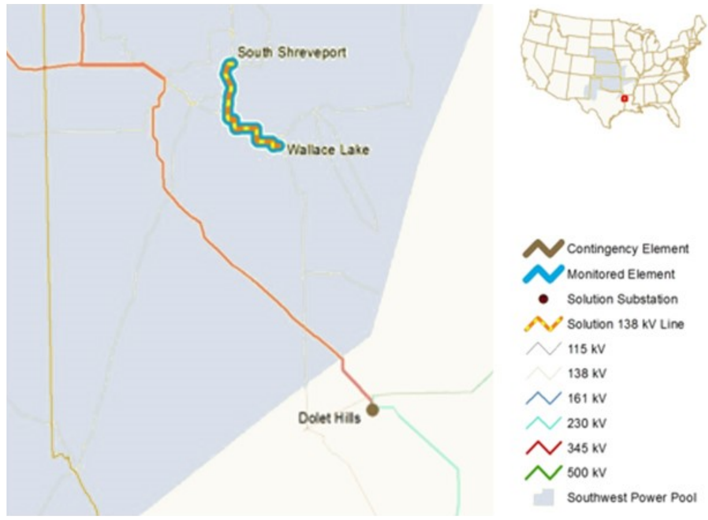
LITTLE ROCK, Ark. — As expected, SPP staff brought a recommendation to the Markets and Operations Policy Committee for approval of one of three interregional projects coming out of the SPP-MISO coordinated system plan study.

The MOPC approved the recommendation. The catch? MISO is not recommending any of the same three projects. (See SPP Staff Recommends 1 of 3 Interregional Projects.)

"MISO has its own processes," said David Kelley, SPP's director of interregional relations. "So far, their analysis indicates they are not willing to move forward with any of the three."

Staff recommended approval of the South Shreveport-Wallace Lake rebuild, an 11-mile 138-kV project addressing area congestion. SPP estimates the project has a cost of $18.5 million, of which it would fund 20% ($3.7 million), and a benefit-cost ratio of 11.86 — far exceeding the 1.0 threshold.

Kelley said three of the South Shreveport-Wallace Lake futures indicate the project yields "significant benefits," 80% of which would go to MISO. He said the RTOs' use the same B/C calculations, "but we use more benefit metrics to determine a project's value than MISO does."



S. Shreveport-Wallace Lake 138-kV rebuild. *Source: SPP*

SPP does not recommend approving the other two interregional projects evaluated as part of a regional review: the Alto-Swartz

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Task Force Debates Clean Power Plan Compliance

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when allocating allowances.

Ellis said EPA believes the need for the safety valve is "highly unlikely" but possible for states with "inflexible requirements on specific" generators.

"The EPA believes most events would be short duration and that emissions standards will not require adjustment," Ellis said.

Xcel Energy's Lauren Quillian questioned that assumption. "The EPA is essentially making the argument that trading will solve everything," she said. "But why not have a reliability safety valve?"

Ellis said staff believes that while some form of a reliability backstop would be beneficial, the roles of FERC, EPA and the Energy Department should be clarified in the event of unforeseen disasters.

Regional Compliance

The qualitative assessment not only reiterated that a mass-based approach has more advantages than a rate-based approach (more liquid trading markets, better planning assumptions, easier measurements and verification, etc.). It also indicated consistent plans among SPP's states would benefit reliability, particularly those that allowed interstate trading of allowances or credits.

Nickell said SPP continues to involve itself as the states in its footprint begin to discuss their approach to CPP compliance. The RTO introduced itself to air regulators last month with a webinar on the plan and its reliability implications, and it has participated in meetings with Missouri, Kansas and Minnesota regulators and legislators. (See SPP to Push Regional Approach in First CPP Webinar.)

Nickell

"They're really appreciating the individual nature of how we can help them," Nickell said. "We want to ensure what the states do doesn't disrupt the regional energy market."

There was some disagreement, however, about whether to involve states outside of SPP's footprint in the compliance process.

"Are there any benefits to working with regions next to ours?" Golden Spread Electric Cooperative's Mike Wise, the task force chair, asked the group.

"We have a big enough problem already, so no, not at this time," Richard Ross of American Electric Power replied.

"I think it's really important to get together with MISO," said Steve Gaw, SPP policy director for The Wind Coalition. "The states are going to do what's best for the state. They don't care whether [the RTOs] are part of one state or the other."

The task force met after the SPC unanimously approved modifications to the group's scope, expanding the group's size from five members to seven (though open participation is welcomed).

The task force is composed of Wise, Burton Crawford (KCP&L Greater Missouri Operations), Dennis Florom (Lincoln Electric), Dale Niezwaag (Basin Electric Cooperative), Wayne Penrod (Sunflower Electric Cooperative), Quillian and Ross. Each of SPP's 14 states is represented by a member.

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series reactor and the Elm Creek-NSUB 345-kV transmission line. Both could be reevaluated in a future regional or interregional study.

With MOPC members wondering how to proceed, Kelley said, "MISO still has [to conduct] a lot of robust discussions with stakeholders over its cost allocations … things we've already done."

MISO has accepted SPP's invitation to participate in a Thursday debrief of the study process, but Kelley sounded skeptical of a positive result. "Unless there are fundamental changes done with MISO's stakeholder process, I don't think [the South Shreveport-Wallace Lake rebuild] will be approved," he said.

SPP Board of Directors Chair Jim Eckelberger said he would talk with his MISO counterpart, Mike Curran, to "see if the project can get legs and move forward."

The two RTOs face a December deadline to come to agreement on the interregional projects, though the current six-month window can be extended. MISO's Board of Directors meets Dec. 10 and will take up staff's recommendation on the interregional projects at that time.

13 Revision Requests Approved

The MOPC approved 13 revision requests from the Market Working Group totaling about $11.5 million.

A request establishing a new incremental long-term congestion rights (ILTCR) allocation process passed the MOPC with 13 abstentions after clearing the MWG with one positive vote and 17 abstentions.

But, as MWG Chair Richard Ross of American Electric Power said, "We knew we had to move it forward. We *have* to do this."

The revision was necessitated by FERC's 2014 order finding fault with SPP's interpretation of long-term congestion rights. The commission rejected multiple rehearing requests in July. (See *FERC Rejects Rehearing on SPP Congestion Rights*.)

The MWG's new process will result in awards to market participants with ILTCRs when a transmission upgrade goes into service, instead of waiting until the annual LTCR allocation. Rights awarded in the initial allocation cannot be renewed; participants with candidate ILTCRs will be eligible to nominate in the same round of the next annual LTCR allocation as load-serving entity LTCRs.

A second revision request concerned the enhanced combined-cycle project, which was suspended last year to allow for a more thorough cost-benefit study and the Integrated System's incorporation. The change is intended to ensure the ECC team implements the market-clearing engine's logic on time and on budget by limiting combined-cycle configurations and offline supplemental offers.

The revision request received the SPP Market Monitoring Unit's blessing and passed unanimously.

Other approved revision requests dealt with quick-start resource improvements, ramp-scarcity pricing and violation relaxation limits.

11 Transmission Projects Withdrawn in Quarterly Review

The MOPC unanimously approved staff's recommendation to withdraw 11 notifications to construct (NTCs) as part of SPP's quarterly review of transmission-expansion projects.

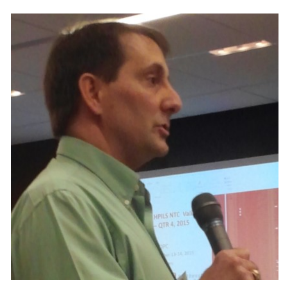
Two of those projects were among seven with out-of-bandwidth cost variances that had their NTCs suspended during the July MOPC meeting until further studies could be conducted. (See "Out-of-Bandwidth Projects Ordered Re-Evaluated," in *SPP BoD/Members Committee Briefs*.)

Antoine Lucas, SPP's planning director, said the additional analysis revealed there was not a reliability need for the Martin-Pantex North-Pantex South-Highland Park 115-kV rebuild (Southwestern Public Service) or the Labette-Neosho SES 69-kV rebuild (Westar). Lucas said a third re-studied project — the Iatan-Stranger Creek 345-kV voltage conversion (Westar/KCP&L Greater Missouri Operations) — should have its NTC reinstated, while the other four out-of-bandwidth projects require further analysis, as a need remains.

"We don't want to continue to defer the [Iatan-Stranger Creek] project but reinstate the NTC because it's still beneficial to the region," Lucas said, referring to its inclusion as an economic project in the 2015 Integrated Transmission Planning 10-year assessment (ITP10).

The other nine withdrawn NTCs came from SPP's re-evaluation of 24 projects at the transmission owners' request. Lucas said staff did not have time to evaluate all of the projects; the 15 remaining projects require further analysis.

MOPC Approves ITP10 Scope


Ross

Members also approved a recommendation by SPP's transmission and economic studies working groups to approve the 2017 ITP10 scope, following a discussion on the use of reliability standards.

Ross noted the scope didn't take into account the North American Electric Reliability Corp.'s coming transmission planning (TPL) standards. "To do the analysis and not be aware of what's coming would be a mistake," he said.

Midwest Energy's Bill Dowling urged incorporating the new TPL-001-4 standards, which take effect Jan. 1.

The committee approved the planning study's scope with four 'nay' votes after inserting language requiring compliance with the TPL standards.

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The study will consider three futures: a regional Clean Power Plan (CPP) solution, a state-level CPP solution and a solution assuming the CPP is not implemented. Each future also assumes competitive wind and solar development, high availability of natural gas due to fracking, expected load growth and inclusion of all statutory and regulatory renewable mandates.

The 2020 and 2025 models will include implementation of the Environmental Protection Agency's interim CPP goals that begin in 2022 and 2025-2027 goals, respectively.

Work Continues on Transmission Planning Improvements

Completion of work to improve SPP's transmission planning processes may slip from January to April, but the result will be a better product, NextEra Energy's Brian Gedrich told the MOPC.

Gedrich said the Transmission Planning Improvement Task Force, which he chairs, needs more time despite adding meetings and conference calls to its schedule. "When I saw the only day we could double up on in December was the 25th, I decided maybe we needed more time," Gedrich told the committee.

The task force faces a January deadline to recommend changes to create more efficient planning processes. Gedrich said the group has already unanimously agreed upon an 18-month planning cycle, a common planning model and a standardized scope. It has also agreed upon a comprehensive planning process that combines the near-term, 10-year and reliability processes into a 10-year study looking at reliability, economic, policy and compliance needs. The current 20-year assessment would be separated from the annual planning cycle.

"We've come a long way and had a lot of great ideas," Gedrich said. "I think it will be fine if we let it slip a little and make sure we get this right."

Eckelberger supported the delay when Gedrich delivered the same message to the Strategic Planning Committee.

"I'm not speaking for the board, but if you need a little more time and you get it really right, let's do that," he said.

The task force envisions overlapping 18-month planning cycles that would produce an annual assessment, with the ensuing cycle's modeling development beginning as soon as the previous one was completed. By using only three futures, Gedrich said, incremental, easier-to-manage changes would be made from one cycle to the next.

The task force will work with other working groups to confirm the feasibility of its recommendations and to identify any other potential issues and solutions. Gedrich said the earliest the new planning cycle could be in place would be April 2019.

Z2 Crediting Task Force Remains on Track

Stakeholders and staff working on the beleaguered Z2 credit project are still targeting January's MOPC and board meetings as to when transmission owners will learn the amount of bills that could be as much as 10 years old. (See *SPP Z2 Project Team Still Grappling with Problem's Size*.)

Bill Grant, Xcel Energy (left), Carl Monroe, SPP, during the presentation on the Regional Tariff Working Group. © RTO Insider

The project team is working to create software that would properly credit and bill transmission customers for system upgrades under Tariff attachment Z2. The problem has been avoiding over-compensating project sponsors and including a way to "claw back" revenues from members who owe SPP money for other reasons.

"It would be helpful to see a number at some point," said ITC Holdings' Marguerite Wagner. "We know the historic stuff. We know how much has been paid by interconnection customers, but interest is accruing on this."

Dennis Reed, director of FERC compliance for Westar Energy and chair of the Regional Tariff Working Group, estimated $750 million for creditable upgrades, with up to $90 million in transmission customer upgrades and the remainder from sponsored upgrades. He has said previously the Z2 team can't produce an accurate number until the software is completed.

"We're not going to be anywhere close to the final numbers, the real size, who's owed and who owes until the first of the year," Reed said. "That's the only time I'll be comfortable with saying how big the breadbox is."

Software is being developed in three different modules (functionality, base calculations and settlement calculations) to help accelerate the process. At the same time, SPP staff has been reviewing previous aggregate transmission service studies dating back to 2005, developing a list of project sponsors and verifying final upgrade costs if the project is still in service.

The team expects to complete historic calculations and develop payment options by April 2016.

Capacity Margin Task Force

Stakeholders working on a task force updating SPP's capacity margin requirements and methodology said last week its preliminary work indicates the RTO can reduce its planning reserve margin from 13.6% to about 10%.

"But we want to vet that with other stakeholders," said Mid-Kansas Electric's Tom Hestermann, who leads the group. "The last thing we want to do is recommend a reduction in planning reserves, and then several years later, have to re-do that."

Hestermann said the task force is focused on bringing more value

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SPP News

SPP Unveils Redesigned Website

By Tom Kleckner

LITTLE ROCK, Ark. — SPP rolled out a flashy, redesigned website last week, culminating several years of effort and months of planning, development and testing.

Designed with non-RTO users in mind, the website adapts to the user's screen size, from flat-screen monitors to tablets and smartphones. Its home page features a real-time price-contour map as well as graphs of generation mixes and load forecasts, all updated every five minutes.

"We laid out the site and organized the site with people other than subject-matter experts in mind," SPP's Derek Wingfield told the Markets and Operations Policy Committee last week. "It's written in a way that's understandable to them."

Wingfield said links to frequently used business-critical pages are prominently displayed on the new home page: the Stakeholder Center, Engineering, Markets & Operations and Regional Entity.

Users will be able to create an account to simplify the meeting registration process. Once a user creates a profile, the user's information is stored and auto-populated when signing up for conference calls or for online and in-person meetings.

However, only meeting registrations through mid-November will be carried over from the old site. Users will have to re-register for any meeting scheduled 30 days or more after the website's Oct. 15 go-live date.

Wingfield said SPP has improved the website's search functionality, calendar and document library, which were frequent targets of stakeholder criticism. SPP's Tariff will still be available in its old format, but the Regulatory and Legal Group page has added a "Notable FERC Filings" link to better sort regulatory dockets.

A link has been added to the home page that explains the new website's layout and major features.

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to the membership from its investment in transmission infrastructure and to provide a way for entities to meet shortages on a short-term basis. He said a preliminary loss-of-load expectation reserve margin study using existing models shows generation is available, "based on the robust transmission system we have."

The task force has three white papers in various forms of completion, including one on deliverability and a second on load-responsible entities (accounting for the fact that not all SPP load is associated with load-serving members).

The third concerns a planning-reserve assurance policy. "We thought enforcement sounded kind of draconian," Hestermann explained.

The team has also suggested a half-day workshop before the January MOPC meeting.

"When we finish our work as a task force," Hestermann said, "we feel strongly someone should take ownership of this process."

Integrated System Increases SPP System's Ramp Rate

SPP's C.J. Brown told members the Integrated System's Oct. 1 integration was a "non-event," with only some tagging and scheduling issues affecting a couple of new market participants. The integration brought on 2,400 MW of load during the transition, with 3,000 MW of generation online.

The system's nearly 2,600 MW of hydro capacity nearly quadrupled SPP's existing hydro. More importantly, Brown said, with its quick ramp rates, the hydropower has increased SPP's rate ramp by 1 MW/minute.

"It may be a minute, but that's a minute across the entire system," he said.

Brown also noted SPP's LMPs have been lowered with the integration, making the RTO more of an energy exporter than it was previously.

Mitigated Offer 'Strike Team' on Hold

SPP's Matt Dillon told the MOPC a "strike team's" work on mitigated offers is on hold following FERC's recent rejection of what costs the RTO can include in mitigated offers. (See *FERC Sides with SPP Monitor*.)

Dillon said SPP has three options: 1) ask for a rehearing, 2) ask for a clarification of "short-run marginal cost" or 3) accept the commission's decision.

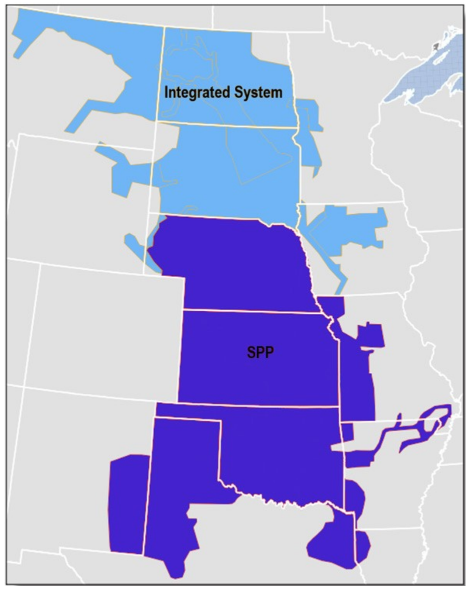
Dillon said SPP remains undecided, and the strike team has no further action.

— Tom Kleckner

SPP News

FERC Rejects Rehearing Requests on Integrated System

By Tom Kleckner



Source: SPP

FERC last week denied multiple requests for rehearing and clarification of its 2014 order that conditionally approved the core Integrated System entities' SPP membership (ER14-2850).

The November 2014 order approved Western Area Power Administration–Upper Great Plains (WAPA-UGP), Basin Electric Power Cooperative and Heartland Consumers Power District's membership into SPP, which became official Oct. 1. The order also granted a federal service exemption to WAPA, which allowed the federal agency to become the first such entity to join an RTO.

At the same time, the order established hearing and settlement judge procedures for SPP's proposed Tariff revisions to allow the entities' membership.

The 2014 order also set several seams issues for settlement procedures but found the perpetuation of pancaked transmission rates between the Integrated System and MISO and between SPP and MISO to be beyond the proceeding's scope. FERC also declined to include issues connected to Corn Belt Power Cooperative and Central Power Electric Cooperative, as neither had yet transferred their facilities to SPP (the two co-ops will join the RTO on Jan. 1, 2016).

MISO, Kansas' State Corporation Commission and Otter Tail Power all filed rehearing requests.

FERC denied the Kansas SCC's request for a rehearing over WAPA's federal exemption and claims that it ignored the latter commission's expert testimony. FERC said its acceptance of the exemption was based on its policy of promoting RTO membership, and that Kansas' expert testimony used SPP's analysis as a baseline in doing its own study of the integration's stakeholder benefits.

The Kansas commission also joined with MISO and Otter Tail in asking for a rehearing on FERC's acceptance of SPP's base-plan upgrade and regional cost-sharing proposal. That request was denied, with the commission finding SPP "crafted a reasonable transition proposal for integrating the current SPP and Integrated System transmission systems."

FERC also denied MISO's argument that the five-year transition proposal for the MISO-Entergy integration should have served as a model for the SPP-IS proposal. The commission said the MISO-Entergy transition proposal was developed, in part, "to prevent unfair subsidization of [project costs] required to make Entergy's transmission infrastructure comparable to MISO's footprint," and that no parties in the SPP-IS proceeding had alleged deficiencies.

The commission rejected another Kansas commission rehearing request regarding the integrated entities' responsibility for SPP's regionally funded legacy facilities. FERC found SPP and the Integrated System "crafted a practical, reciprocal cost allocation approach for facilities in service before the integration date that is consistent with commission precedent."

Committee Ponders Response to Lubbock's ERCOT Move

By Tom Kleckner

LITTLE ROCK, Ark. — Lubbock Power & Light's recent announcement it was planning to take 400 MW of SPP load and join ERCOT hung heavy over the Strategic Planning Committee last week as it tried to determine what to do next.

Golden Spread Electric Cooperative's Mike Wise, the SPC chair, teed up the issue by asking whether SPP staff should conduct a transmission study of the area to determine whether LP&L's departure would result in stranded investment.

"Transmission is built for and paid for by everybody," Wise said. "Will there be transmission infrastructure out there that wouldn't be needed if LP&L leaves?"

"I can tell you no facilities were built just for Lubbock," said Bill Grant of Xcel Energy, which currently provides all of the city's energy (forecast to be 626 MW in 2019) through its Southwestern Public Service subsidiary.

Effective June 1, 2019, when LP&L will also begin receiving power as a member of ERCOT, Xcel will provide only 170 MW of Lubbock's needs.

"What led to this, and what can we do about it? Will this be the first time or the last time it happens?" Grant asked.

SPP Director Harry Skilton echoed Grant, expressing a need to "understand [LP&L's] motivation and whether we should be doing something to alleviate whatever incentive they had for moving."

LP&L, the third-largest municipal electric utility in the state, said joining ERCOT will reduce its energy and capacity costs. (See *Integrated System to Join SPP Market Oct. 1; Lubbock Looking at ERCOT*.)

"Prices in the ERCOT area are lower than SPP's. We can debate whether that's temporary or not," said Carl Monroe, SPP's executive vice president and COO. "The second issue is we have a capacity-margin requirement, and ERCOT doesn't."

"Load will come and go. Businesses move from one location to another," said Dogwood Energy's Rob Janssen. "Let's face it … ERCOT built transmission lines in West Texas that overlap with SPP's, so some customers in the area have a choice as to which

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SPP NEWS

Strategic Planning Committee Briefs

SPC, Finance Committee Develop Operating Plan

Desselle

LITTLE ROCK, Ark. — The Strategic Planning and Finance committees are collaborating on an effort to establish an operating plan that will create "line of sight from the strategic plan down to the budget," said Michael Desselle, SPP vice president and chief compliance and administrative officer.

"It will ultimately drive what we do as an organization," Desselle told the SPC and the Markets and Operations Policy Committee last week. "Doing this annually will add clarity and show us where we stand financially, with our budget items and our expense categories."

The operating plan is linked to the strategic plan's initiatives in three ways: 1) staff projects such as the enhanced combined-cycle and gas-electric harmonization; 2) technological investments that help achieve the projects; and 3) the business-as-usual, keeping-the-lights-on everyday work.

The plan will prioritize projects by categorizing them as mandatory projects that will spend their budget allocations; optional projects that might spend their budget; or projects that can be canceled should the first two categories need the money.

SPC Expands Committee by 2 Members

The SPC unanimously approved a recommendation to revise its charter to add two members, reflecting the recent addition of the Integrated System.

"There is enough of a reason, with the variety of members in the [Integrated System], to add one transmission owner and one transmission customer," Desselle said. He said the governance committee will work to maintain geographical diversity and the proper mix of size and member types.

The SPC currently numbers 11 members: four transmission-owning and four transmission-using representatives, and three from the Board of Directors.

The SPC forwarded its recommendation to the Corporate Governance Committee for consideration.

SPP Continues Talks with Western Neighbors

SPP's Carl Monroe told the committee there are "ongoing talks with our western neighbors," but no serious discussions about potential new members.

SPP has an ongoing market-consulting contract with the Northwest Power Pool, which has been exploring the possibility of opening an energy market for several years. Two of the NWPP's members, Puget Sound Energy and Portland General Electric, recently announced their intention to join CAISO's energy imbalance market, though, as Monroe noted, Portland General is "considering all options."

SPP's membership will increase to 94 on Jan. 1, when Tri-State Generation and Transmission Association Cooperative and Central Power Electric Cooperative join the RTO. SPP currently has 166 active market participants.

— Tom Kleckner

Committee Ponders Response to Lubbock's ERCOT Move

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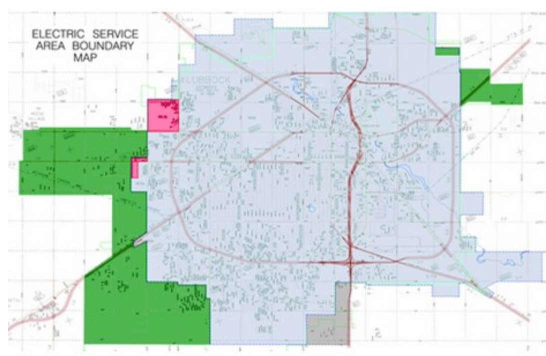
system to be on."

Monroe said SPP has no withdrawal fees to discourage load from leaving the RTO. "The only withdrawal provisions we have today are for withdrawn transmission, not load."

SPP Vice President of Engineering Lanny Nickell said SPP could run studies of the areas. He also said SPS, which has owned the transmission interconnection with LP&L since 1983, could also request re-evaluations of notifications-to-construct to determine whether planned projects are still needed.

Asked whether any projects with NTCs in the area might be affected by the withdrawal of LP&L's load, Nickell said he "was not aware of any projects directly impacted by Lubbock leaving."

Grant said Xcel has identified a couple of impacts on its radar screen, and it will "take a closer look when the projects get close to breaking ground." But he cautioned that the committee might be getting ahead of itself, pointing out LP&L has only announced its intent to join ERCOT and that the Texas grid still must conduct a feasibility study.



LP&L service territory *Source: LP&L*

"We'll know when the studies are done … we'll know way before June '18," he said, referring to LP&L and ERCOT's final decision date. "We'll know in time what we need to reflect in our own models."

In the meantime, SPS has filed a Freedom of Information Act request to obtain LP&L's feasibility study, Grant said.

"We have no idea what numbers they came up with, or how they came up with the numbers, or whether they're feasible," he said.

FERC NEWS

Commission Refines Market-Based Rate Rules

By Michael Brooks

WASHINGTON — FERC last week issued a final rule to clarify and streamline its market-based rate (MBR) program, the first major update to the policy since codifying it in Order 697 in 2007 (RM14-14).

The changes are intended to increase transparency by, for example, requiring that asset appendices in MBR filings be submitted electronically so that they are searchable and sortable. MBR sellers will also be required to report all long-term firm purchases of capacity and energy that have associated long-term firm transmission.

FERC, however, eliminated some requirements in an effort to streamline the program. For example, MBR sellers will no longer be required to file quarterly land acquisition information for new generation sites. They will also no longer be required to report behind-the-meter generation in their asset appendices.

The commission issued its Notice of Proposed Rulemaking for the changes in June 2014. The final rule did not adopt the NOPR proposal to relieve MBR sellers in RTOs and ISOs of the obligation to submit horizontal market power screens, but FERC said it might reconsider this in the future. (See *FERC to Revamp MBR Rules*.) Commissioner Colette Honorable credited this to stakeholder feedback on the NOPR.

FERC Denies PNM MBR Authority

In a related order, FERC rejected Public Service Company of New Mexico's (PNM) request for MBR authority in its balancing authority area (ER10-2302).

The company's August 2014 request relates to its purchase of Delta Person, the owner of a 132-MW gas-fired power plant in PNM's balancing authority. PNM sought to reinstate its MBR authority because, it said, market characteristics in its balancing authority area had changed since it relinquished its MBR authority in 2010.

Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
ABC Corp.	ER05-23X-000	ABC falls plant #1	ABC Corp.	ABC Corp.	NA*	ABC balancing authority area	Central	8/12/1981	153.5 MW (seasonal)
xyz Inc.	ER94-79XX-000	NA	NA	NA	NA	NA	NA	NA	NA
RST LLC	ER01-2XX5-000	Green CoGen	WWW Corp	RST LLC	5/23/2005	New York ISO	Northeast	12/20/2003	2000 MW (nameplate)
Sample Co.	ER03-XX45-000	Sample Co. 3	Sample Co.	YYY Corp	2/1/1982	Sample Co. balancing authority	Southwest	5/13/1973	10 MW (seasonal)

Sample market-based rate authority asset appendix. *Source: FERC*

FERC questioned the data with PNM's application, including the simultaneous transmission import limit (SIL) study values included in its market power analysis. The study is performed by simulating an increase in generator output in one area, the export area, and a decrease in output in the area under study.

FERC found that PNM had improperly decreased output from plants with long-term firm transmission reservations, which are exempt from scaling in the study. As a result, the commission said that PNM's values were invalid and that its analysis failed to rebut the presumption of horizontal market power in its balancing area.

FERC emphasized in its order that many companies used incorrect information in their market power analyses.

"We take this opportunity to remind applicants seeking initial market-based rate authority or seeking to retain such authority of the type of information and analysis that is useful and appropriate for our consideration of a delivered price test (DPT) and what is not," the commission said in its order. "We are providing this information not only to PNM but to industry broadly with respect to several issues that arose in our review of the DPT analysis and SIL study prepared by PNM."

"PNM was just the lucky person we chose to use their order as the vehicle to deliver this guidance," Commissioner Cheryl LaFleur said at FERC's open meeting Thursday. "I hope that the guidance will be helpful to applicants to make their application processes smoother and faster in the future."

Honorable agreed. "Our intention certainly wasn't to single out PNM," she said.

FERC News

Generator Tie-Line Exemption Upheld by Commission

By Rich Heidorn Jr.

FERC last week denied requests for changes to Order 807, which granted a blanket waiver from Open Access Transmission Tariff requirements to owners and operators of generator tie lines (RM14-11-001).

The commission's April order also allowed generators to reserve excess capacity on their tie lines, or "interconnection customer's interconnection facilities (ICIF)," for the first five years of operation. (See *Generator Tie Lines Exempted from OATT Rules*.)

The commission denied a rehearing request from the National Rural Electric Cooperative Association (NRECA) and a second filed jointly by the American Public Power Association (APPA) and the Transmission Access Policy Study Group (TAPS).

Safe Harbor

NRECA asked the commission to reconsider its presumption that an ICIF owner has plans to use its capacity when the third-party requesting transmission service is a load-serving entity.

NRECA noted that renewable generating resources are often located in remote areas and require long tie lines to connect to the interstate grid. The group said it would be more efficient for an LSE to contract with an ICIF owner to counterflow power over the line rather than to build a new facility to serve its native load.

It said the tie line owner should have the burden of proving it has specific plans to use the excess capacity that would prevent it from providing LSEs access.

FERC said it disagreed with NRECA's contention that the five-year safe harbor period "impinges upon the reasonable needs of LSEs."

"Because of the case-specific nature of any request under sections 210 and 211 to use certain ICIF, we cannot … state exactly what evidence would be strong enough to overcome the rebuttable presumption during the safe harbor," FERC added.

Open Access

FERC also rejected the allegation by APPA and TAPS that the rule grants tie line owners vertical market power over access to their facilities. The groups said FERC unfairly ruled that third parties would not be unduly burdened by pursuing transmission service under Federal Power Act sections 210 and 211.

The commission said its rule "does not foreclose access" to tie lines but sought to reduce unnecessary regulatory burdens for owners that may plan to use excess transmission capacity for future phases of generation construction.

"Without such reasonable assurance, there would be little incentive for a developer to shoulder the extra expense of ICIF sized larger than the initial phase of the project," the commission said.

Clarification

The commission clarified that no commission proceeding is necessary for a blanket waiver to be revoked if the public utility acquires additional transmission facilities that are not ICIF or otherwise no longer qualifies for the exemption. FERC said the waiver would be automatically revoked and the owner would be required to file an OATT within 60 days.

FERC also clarified that non-public utility ICIF owners may also take advantage of the blanket waiver and safe harbor period.

"Although the determination in the final rule does not explicitly state that non-public utility ICIF owners may take advantage of the blanket waiver, this omission was unintentional," the commission said. "The intent of the final rule was to make the package of reforms equally available to nonpublic utility ICIF owners."

SCOTUS Agrees to Hear Md., NJ-FERC Subsidy Cases

By Ted Caddell

The Supreme Court announced yesterday that it will rule on two federal-state jurisdictional cases pitting New Jersey and Maryland regulators against FERC.

The court said it would consider orders by the 3rd and 4th U.S. Circuit Courts of Appeals that upheld lower court rulings throwing out contracts in which generation developers won state-issued subsidies to build plants in the two states.

Competitive Power Ventures and state regulators have argued that the subsidies are legal. The courts ruled with PPL and other plaintiffs in saying the subsidies violated FERC jurisdiction over the wholesale electric market.

The cases revolve around two generating projects — a 660-MW combined-cycle plant in Maryland and a 663-MW plant in Woodbridge, N.J.

CPV won a solicitation by the New Jersey Board of Public Utilities to provide a 15-year capacity agreement, and one from the Maryland Public Service Commission to build a plant in the Southwest MAAC zone. PPL was joined in its challenge of the contracts by Calpine, Essential Power and Lakewood Cogeneration.

CPV and the regulators are asking the high court to reinstate the contracts. CPV has gone ahead with its construction plans, despite losing a subsequent ruling by FERC. (See *CPV Md. Plant Goes Forward Despite FERC Ruling*.)

The Supreme Court will hear one hour of arguments on two questions:

1. When a seller offers to build generation and sell wholesale power on a fixed rate contract basis, does the [Federal Power Act] field-preempt a state order directing retail utilities to enter into the contract?

2. Does FERC's acceptance of an annual regional capacity auction preempt states from requiring retail utilities to contract at fixed rates with sellers who are willing to commit to sell into the auction on a long-term basis?

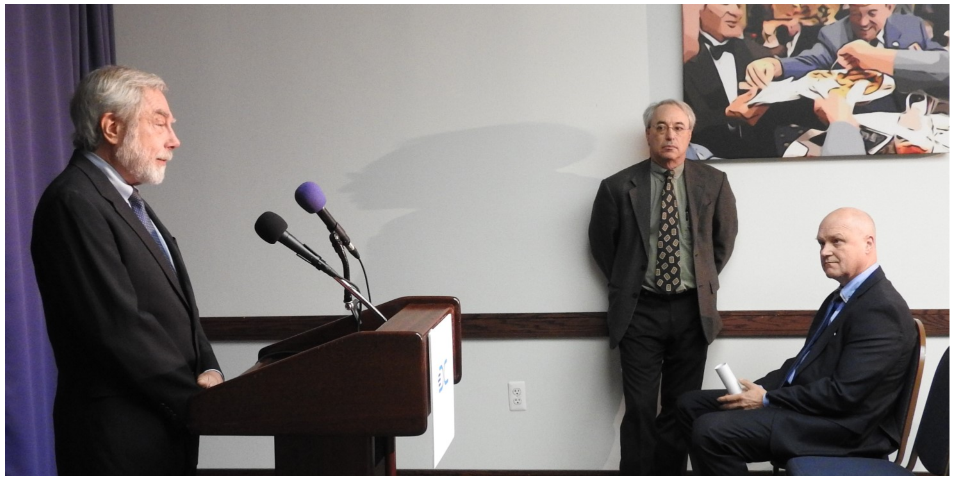
DC Public Power Proposes to Buy Pepco's DC Assets, Form Publicly Owned Utility

Continued from page 1

the proposal Friday morning at the National Press Club.

"Additional benefits will accrue by maintaining local ownership and presence as well as additional economic activity," added board member John Chelen.

In its filing, DCPP also objected to the Public Service Commission reopening the record for Exelon's proposed $6.8 billion acquisition of PHI and requested late intervenor status because the group was formed April 30, after the filing deadline for joining in the case. Other parties also objected to reopening the record. (See related story, *Opposing Parties to DC PSC: Require a New Exelon-Pepco Merger Application*, p.28.)



Left to right at the press conference: John Chelen and Michael Siegel, DC Public Power board members, and Michael Overturf, DC Public Power president and CEO © RTO Insider

'Strong Interest' from Lenders

Chelen said the group had received "strong interest" from "recognized investment banks" in financing the deal, which would occur after Exelon consummates the purchase.

The group said the utility's debt would be "an extremely secure and attractive investment" because of the district's strong economy and low interest rates for alternative investments.

It said PHI D.C.'s book value was $1.4 billion as of March 2013 — though shareholders would certainly seek a higher price in any sale.

Chelen said the group already had approached Exelon with its interest but was turned down.

DCPP board member Michael Siegel © RTO Insider

Exelon, Pepco: No Deal

In a letter included in the filing, Exelon and PHI attorney Mark Director wrote that the concept "raises many complex legal, financial, regulatory, operational and commercial considerations. It would require substantial time to evaluate those complexities, and that would complicate and delay, rather than simplify and streamline, matters to be considered by the D.C. PSC and would require approvals from other regulatory authorities.

"As Exelon and PHI remain committed to completing their merger as promptly as possible, the companies do not believe it would be productive to have further conversations about your proposal."

Said Chelen, "DCPP had, in fact, structured its proposal to be as uncomplicated as possible with the intent of facilitating Exelon's and PHI's ability to complete their merger. Perhaps the real reason is they were able to attract a better deal for them from the mayor and D.C. officials."

That settlement was presented Oct. 6 to the PSC, which denied the merger as filed on Aug. 25 as not being in the public interest. (See *Mayor's Settlement Puts DC PSC on the Spot in Exelon-Pepco Deal*.) The proposal envisions a non-profit board hiring an experienced utility operator to run day-to-day operations, similar to Long Island Power Authority's contract with Public Service Enterprise Group.

Exelon referred a request for comment to Pepco. A PHI spokeswoman said Thursday that a district-only system would be "expensive and inefficient."

Myra Oppel, regional communications vice president at PHI, said the group's proposal "raises many complex legal, financial, regulatory, operational, commercial and customer considerations that the group has not begun to address."

The group said it had discussed its proposal with numerous city leaders but not directly with Mayor Muriel Bowser. "Some people are wildly enthusiastic," said Chelen. "Other people are guarded."

Public Power in Cities

Of the about 2,200 power providers in the U.S., about 2,000 are public power, including Seattle, Los Angeles, Sacramento, Austin, Jacksonville and Cleveland. Only 200 are investor-owned utilities, though they tend to be in bigger cities.

The group said public power agencies similar to that of Chattanooga, Tenn. — a city about 60% the size of the district — have "extremely high capital productivity," unlike IOUs, whose profits can increase with higher spending.

"From our point of view, the [Exelon-Pepco] deal relies on an extremely complex, vague and opaque non-unanimous settlement agreement [NSA] that will be a nightmare to monitor and enforce," Chelen said.

"What is most disturbing is it calls upon divestiture that is the severance of Pepco D.C.-based assets as an ultimate means to ensure compliance," he said. "The inclusion of this provision affirms that divestiture is the best method to secure the public interest. The NSA severance clause amounts to exclusive acknowledgment that the NSA is a risky deal for the district."

COMPANY BRIEFS

Calpine Pays $500M for 745-MW NH Power Plant

Calpine has agreed to buy the 12-year-old Granite Ridge Energy Center in Londonderry, N.H., for $500 million, or about $671/kW, the company said last week.

The 745-MW combined-cycle, gas-fired plant is located 45 miles north of Boston in ISO-NE. The acquisition will bring the company's generation resources in the region to about 2,000 MW.

The plant, which went into operation in 2003, features two combustion turbines, two heat recovery steam generators and one steam turbine.

More: Calpine

Xcel Completes Segment of $2B, 800-Mile Tx Project

Xcel Energy has completed its 90-mile, 345-kV segment between Minnesota and Wisconsin of the CapX2020 Hampton-Rochester-La Crosse transmission project. The project is 800 miles and begins in the Dakotas with two separate lines that converge in Minneapolis-St. Paul. The new segment terminates in Holmen, Wis., but the project will eventually extend to Madison.

The $2 billion project is expected to be completed in 2016. It is the area's biggest upgrade of the transmission system in decades, according to project developers.

More: *Post-Bulletin*

Continued on page 29

Opposing Parties to DC PSC: Require a New Exelon-PHI Merger Application

By Suzanne Herel

The D.C. Public Service Commission should not reopen the record to consider a newly reached settlement in Exelon's proposed $6.8 billion takeover of Pepco Holdings Inc., parties opposed to the deal said in a filing Friday.

PSC rules prohibit settlements to be submitted after a final decision, the group said, referring to the commission's Aug. 25 rejection of the merger as not in the public interest. The group argued that the commission should require the companies to file a new application.

The group represents DC Solar United Neighborhoods, Grid 2.0 Working Group, Mid-Atlantic Renewable Energy Coalition and Maryland DC Virginia Solar Energy Industries Association.

The settlement, brokered by Mayor Muriel Bowser's administration, was filed Oct. 6 in an attempt to persuade the commissioners to approve the deal, which has been approved by FERC, Delaware, Maryland, New Jersey and Virginia. (See *Mayor's Settlement Puts DC PSC on the Spot in Exelon-Pepco Deal*.)

Regardless of the agreement, the filing said, "the public continues to share the commission's concern that the 'potential conflicts of interest inherent in Pepco's role and its parent company's policy positions and interests might inhibit our local distribution company from moving forward to embrace a cleaner and greener environment.'"

The prevailing concern involves Exelon's commitment to its generation assets, in particular to its partly struggling nuclear fleet.

To shore up that point, the filing includes more than 800 emails from district residents opposing the merger, most using a template letter saying in part, "I am dismayed by the D.C. government's behind-the-scenes Exelon settlement. Their secretive process took place over the objection of the majority of D.C. ratepayers. … Your unanimous ruling against the merger, and the thorough process that preceded it, restored faith in the district's democratic institutions. Anything less than a full process now would deprive D.C. residents of our due process rights."

The petitioners acknowledge that the commission has the right to waive its own rules, but they advised it not do so because of the unprecedented interest the case has drawn — more than 3,000 commenters, the most in the agency's more than century-old existence.

"Many of the interested customers or groups have justifiably relied on the formal parties to present and champion their positions, including particularly the District of Columbia government and the Office of the People's Counsel," the filing said. "Now, both the district government and OPC have acceded to the terms that the joint applicants offered, so they no longer reliably represent the views of residential customers or groups that are unwilling to concede to Exelon.

"The realignment of some parties with Exelon and Pepco effectively muffles the public's voice in any proceeding that merely reopens the existing case and that does not give other interested individuals or organizations a full opportunity to participate as parties."

They allege that reopening the case would set a dangerous precedent for future applicants seeking to negotiate a settlement only after the commission has highlighted the deficiencies in their filing.

Friday was the deadline to submit comments regarding the joint applicants' request to reopen the case.

Also filing opposition was D.C. Public Power, which at the same time submitted its intent to buy Pepco's district assets and requested to become an intervenor. (See related story, *DC Public Power Proposes to Buy Pepco's DC Assets, Form Publicly Owned Utility*, p.1.)

In addition, the Ward 3 Democratic Committee submitted a filing saying that the settlement amounts to a new proposal and should be treated as such under a new application.

Company Briefs

Continued from page 28

165 MW of Solar Power Coming Online in New Mexico

By the end of 2016, New Mexico will be producing another 165 MW of solar electricity from three large-scale generating facilities scheduled to go into service near Roswell and Deming.

Xcel Energy subsidiary Southwest Public Service has signed a long-term power purchase agreement with NextEra Energy Resources to build and operate two 70-MW solar sites, which will be the largest photovoltaic facilities in the state.

Tri-State Generation and Transmission Association, a wholesale power supplier for 44 electric cooperatives in New Mexico and three other states, also announced a deal with D.E. Shaw Renewable Investments and Denver-based TurningPoint Energy for a 25-MW solar facility in southeast New Mexico.

More: Albuquerque Journal

Ameren Adds Luminant's Flores to Board of Directors

Rafael Flores, senior vice president and chief nuclear officer for Texas generator Luminant who is scheduled to retire at the end of the year, has been elected to Ameren's board of directors effective Nov. 1. Flores' election increases St. Louis-based Ameren's board from 11 to 12.

Warner L. Baxter, Ameren's chief executive, said Flores' extensive nuclear operating experience will help guide Ameren, whose Callaway Energy Center is "a critical nuclear generation resource in providing safe, lean, reliable and reasonably priced energy."

Flores has announced his retirement effective Dec. 31 after 32 years with Luminant. He oversees operations of the Comanche Peak nuclear plant southwest of Fort Worth and is active with the Nuclear Regulatory Commission, the Institute of Nuclear Power Operations and the Nuclear Energy Institute. He also serves on various committees and working groups in the nuclear industry.

More: Ameren

Westar Announces 3 Gas Plants To Shut Down by Year's End

Westar Energy announced plans last week to shut down three of its older gas-fired peaking units in Kansas by the end of the year. The move will mean the loss of 40 jobs, though Westar indicated it would give employees positions within the company.

Westar will close a 50-year-old, 167-MW combustion turbine at the Hutchinson Energy Center. It is also decommissioning a gas generator installed in 1962 at the Tecumseh plant near Topeka and another operating since 1954 in Lawrence.

"People are using less energy, so we no longer need these old, small generating units to meet peak electrical demand," said John Bridson, Westar senior vice president of generation. "Plus, the current price to add more renewable energy is a reasonable alternative, so we'll add more renewable energy, as needed." The utility said its emission-free energy will equal more than 40% of its retail demand next year.

More: The Hutchinson News; Westar

BNE Erects Connecticut's First Wind Farm Project

BNE Energy and Connecticut political leaders celebrated the launch of the state's first commercial wind project by putting a mammoth turbine into service in Colebrook.

Two of the three turbines that were approved for the site have been erected at the 10-acre property, which is 1,500 feet above sea level. Once both wind turbines are operational, they will produce about 5 MW. BNE will not erect the third turbine until it secures a contract for the electricity that unit produces.

BNE Energy has a 20-year contract to sell the power produced by the two turbines to Eversource Energy. From 2011 to 2014, Connecticut was the only state in the country to ban wind farm development.

More: New Haven Register

DTE Plans to Close Its 40-MW Biomass Plant

Citing market conditions, DTE Energy announced it is closing a 40-MW biomass plant in Cassville, Wis. DTE bought the E.J. Stoneman Electrical Station, a former coal-fired power plant, in 2008 and converted it to burn wood waste in 2010.

The power from the station was sold to Dairyland Power Cooperative. DTE said the plant was under pressure to generate affordable energy in the face of falling electricity prices from renewable energy projects in the region.

More: Biomass Magazine

FirstEnergy Progressing on $260M Dewatering System

FirstEnergy is working to complete a dewatering facility at its giant Bruce Mansfield plant in Pennsylvania, which is expected to resolve the plant's coal ash disposal issues. FirstEnergy has to complete the system in order to keep the 2,490-MW plant running after a Jan. 1, 2017, deadline for various emissions and ash-storage mandates.

"It's a challenge, but we like challenges," said James Fitzgerald, FirstEnergy manager of special projects. The facility will be able to handle between 2.5 million and 3 million tons of coal ash slurry per year. Once the ash is dried, it will be trucked to a number of company-owned disposal sites. The final destinations have not yet been decided, but one could be at the company's Hatfield's Ferry station in Fayette County, Pa. That power plant was retired in 2013.

The dewatering project is estimated to cost $260 million, up from initial estimates of $200 million.

More: TribLive

NRC Launches Inspection of Dominion's Millstone

The Nuclear Regulatory Commission initiated an inspection of Dominion Resources' Millstone Unit 2 nuclear station in Connecticut after a leaking relief valve was found. The discovery triggered the declaration of an "unusual event" Oct. 4 at the plant, the lowest of four emergency classifications.

Millstone was preparing to power down for a refueling outage when the event occurred. NRC officials said the event raises questions about operator performance, and so it ordered an inspection.

More: Associated Press

FEDERAL BRIEFS

NRC's Burns Tours Fermi 2, Pleased with Upgrades

Nuclear Regulatory Commission Chairman Stephen Burns last week toured DTE Energy's Fermi 2 nuclear generating station and said he was impressed with the upgrades made to the plant in the wake of the 2011 Fukushima disaster in Japan.

Fermi 2, which went into service in 1985, is equipped with the same type of General Electric Mark 1 reactor as the Fukushima plant, but it is 14 years younger than the Japanese reactor.

Burns and U.S. Rep. Tim Walberg (R-Mich.) toured the plant during a refueling outage. "The plant condition looks good," Burns said. He was briefed mostly on upgrades to the plant's ventilation system, a weak point in the Fukushima design.

More: *Toledo Blade*

NRC says Chatham House Report 'Based on … Hearsay'

The Nuclear Regulatory Commission last week blasted a report by a British think tank asserting that U.S. nuclear power plants are at risk from cyberattacks. London-based Chatham House issued the report recently, saying the "risk of serious cyberattack on civil nuclear infrastructure is growing" because they rely on commercial "off-the-shelf" software.

NRC said the Chatham House report "is based on generalizations and hearsay." It argued that "the NRC has been very forward-leaning on cyber security issues, and as a result the nuclear power industry is probably better protected than any other sector of our critical infrastructure."

The Chatham House report did acknowledge that U.S. nuclear plant operators have taken steps to make them more secure from hacking but said more needs to be done.

More: *Morning Consult*

Obama Administration Sends $15M To Bolster Coal State Economies

The Obama administration awarded $15 million in grants to fund workforce projects in coal-producing regions whose economies have suffered because of stricter federal environmental regulations.

The coal industry has shrunk and faces more pressure in the face of federal emissions regulations, low natural gas prices and the growth of renewable energy. The federal grants will fund retraining programs under Partnerships for Opportunity and Workforce and Economic Revitalization initiatives.

"These grants will help each community create new jobs, diversify its economic portfolio and better compete in the 21st century," Commerce Secretary Penny Pritzker said.

More: *Reuters*

PennEast Pipeline Intervenor Numbers Growing, FERC Says

The number of parties seeking to be heard concerning the PennEast Pipeline, which is planned to run from northeast Pennsylvania to New Jersey, is growing, according to FERC officials. The deadline for comments or to file for intervenor status is Oct. 29, a FERC spokeswoman said.

While FERC takes public comments into consideration, intervenors have legal status. There are 366 separate intervenor applications filed so far.

PennEast's developers aren't daunted by the number, however. A spokeswoman said there is a lot of community support for the proposed $1 billion, 114-mile natural gas pipeline. "There might be some people who are opposed to natural gas development, but there are a far greater number of people who want to receive clean, locally produced natural gas at reduced rates," PennEast spokeswoman Patricia Kornick said. "They just aren't on the docket."

More: *Standard Speaker*

Feds Take Two Steps To Slow Arctic Drilling

The Interior Department has announced it will suspend two upcoming auctions for offshore Arctic drilling rights, while rejecting the requests of two companies to explore for oil under their existing leases. The moves represent two more steps taken by the Obama administration to put the brakes on energy exploration in the region.

The department said it would cancel the previously scheduled auctions in 2016 and 2017 in the Chukchi and Beaufort seas, citing low industry interest and plunging oil prices. It also denied requests to extend leases by Shell and Statoil for parcels in the same areas, mirroring earlier actions taken against leases held by ConocoPhillips.

Secretary of the Interior Sally Jewell said the government was taking the action in response to Shell's recent announcement that it was suspending exploration efforts in the Arctic, citing market conditions. "In light of Shell's announcement, the amount of acreage already under lease and current market conditions, it does not make sense to prepare for lease sales in the Arctic in the next year and a half," she said.

More: *FuelFix*

Application for Pennsylvania Hydro Project Submitted to FERC

A Pennsylvania developer has submitted an application to FERC for a preliminary permit for a hydropower facility to be built at the Blue Marsh Dam on a Delaware River tributary.

Developer Adam R. Rousselle II of New Hope wants to develop a hydropower project at an existing dam built in 1979 to control flooding of Tulpehocken Creek. The Delaware River Basin Commission had a preliminary permit to study such a facility at the same location, but that permit expired four years ago.

Rousselle is seeking a permit for a 2,500-kW generator. If the preliminary permit is approved, he will have three years to develop more studies on the project and submit a more detailed plan to FERC. The U.S. Army Corps of Engineer would also be involved in the approval process.

More: *Reading Eagle* (subscription required)

State Briefs

ILLINOIS

Naperville Muni Showing $13.2 Million Shortfall

Naperville's municipal power provider has a $13.2 million shortfall, officials said. Since 2011, according to records, Naperville's energy costs have exceeded projections every year, and by as much as 16% during fiscal 2014.

Much of the overrun can be traced to the utility's membership in the Illinois Municipal Electric Agency and the assumed costs from the problem-plagued Prairie State Energy Campus. IMEA owns 15% of the project, which is expected to cost $4 billion and has experienced 25% in construction-cost overruns. Naperville and other IMEA members are paying a share of the overruns each month.

Former Naperville Councilman Bob Fieseler said the project's costs add about $5 to every monthly residential electric bill.

More: *Chicago Tribune* (subscription required)

INDIANA

Consumer Advocate Comes out Against Vectren's EE Plan

The Utility Consumer Counselor is opposing Vectren's proposal to boost rates to pay for its energy efficiency program, saying it would result in higher customer charges than are necessary.

UCC spokesman Anthony Swinger said Vectren already makes enough to fund the program without charging customers. Vectren proposed charging $1.10/month for residential customers to fund the program. Vectren said the program encourages energy conservation and affects the company's bottom line.

More: *Associated Press*

LOUISIANA

Low Energy Prices to Sap State's Economic Growth

Low energy prices will stunt the state's economy over the next two years, although massive industrial projects will help drive job gains in the Baton Rouge and Lake Charles areas, according to an economic forecast released last week.

"Louisiana Economic Outlook: 2016 and 2017" projects that the state will add 15,400 jobs in 2016 and 19,600 in 2017. "Normally these numbers would be a lot better except for what's going on in the oil patch," said economist Loren Scott, co-author of the report.

The economic forecast also says new federal ozone rules could raise electricity rates so much that Baton Rouge may not be able to compete for new industry. Scott said the narrowing gap between the price of natural gas in the U.S. versus Europe and Asia may also slow industrial growth.

More: *The Advocate*

MARYLAND

Gov. Hogan Shaking Up Energy Administration


Hogan

Environmentalists fear Gov. Larry Hogan's administration is retreating from the previous Democratic administration's support of renewable energy and energy efficiency after he shook up the state's Energy Administration last week by firing two senior managers and moving the agency's headquarters from Annapolis to Baltimore. The Republican also stated his opposition to raising rates to pay for energy efficiency efforts.

"The administration's apparent hostility toward nationally recognized energy efficiency programs in this state is deeply troubling," said Mike Tidwell, executive director of the Chesapeake Climate Action Network. "The No. 1 way to lower ratepayers' bills is to invest in efficiency."

A Hogan spokesman brushed off the concerns. "The governor and the director are 100% committed to continuing the great work the agency does," spokesman Doug Mayer said. "This administration is against raising fees."

More: *The Baltimore Sun*

PSC Appoints 2 To Staff Positions

The Public Service Commission has promoted Dan Hurley to director of the energy analysis and planning division and hired Tori Leonard as director of communications.

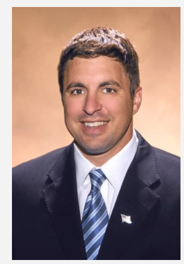
Hurley will oversee the agency's energy efficiency and conservation programs, smart grid implementation and the state's new renewable energy portfolio standard. Leonard will manage communications, media relations and social media.

Hurley, who joined the PSC in 2006 as a regulatory economist, has been an assistant director in the department since 2009. Leonard was the public relations manager at Rosborough Communications, working with the firm's transportation clients.

More: *Maryland Public Service Commission*

MASSACHUSETTS

Energy Sec.: Pilgrim's Loss Means Time to Look at Hydro


Beaton

Entergy's decision to shut down its Pilgrim nuclear generating station will leave the state looking for other ways to meet federal and state clean energy goals, and Energy and Environmental Affairs Secretary Matthew Beaton said Canadian hydropower could help.

The loss of Pilgrim is significant, he said. "It's a big step back in meeting our Global Warming Solutions [Act] targets because it was over 80% of the clean energy we had to help us towards our clean energy goals," Beaten said, "making it all the more important to see the other policy solutions we are pursuing actually happen."

He said it may be possible to import hydropower from Quebec, an option explored by Gov. Charlie Baker.

More: *Boston Herald*

MICHIGAN

25 Coal Plants Set to Retire by 2020

Power producers are set to retire 25 coal-fired plants in the state by 2020, citing aging equipment and increasing environmental restrictions.

Coal currently provides more than 50% of the state's electricity supply. Industry ex-

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perts expect the state to replace the lost coal power by importing power through the regional grid and from new construction of gas-fired and renewable sources.

Under the Clean Power Plan, Michigan must reduce carbon emissions by 39% from 2012 levels by 2030. According to the U.S. Environmental Protection Agency, the state is on course to reach a 17% reduction by 2020. In September 2016, officials will be asked to hand over a plan detailing how the state will comply with the new regulations.

More: *Detroit Free Press*

State is on Track to Meet Energy Mandates

The state is on target to meet mandates set in 2008 to generate about 10% of its energy from renewable sources.

Gov. Rick Snyder outlined a renewable energy plan in March, encouraging the state to meet up to 40% of its power demand through "energy waste reduction, increased use of natural gas and renewable energy sources."

According to the Public Service Commission, almost half of the state's renewable energy comes from wind, 17% from landfill gas and solid waste and about 10% from hydroelectric. Solar power represents less than 1%.

More: *Detroit Free Press*

MISSOURI

AG Koster says State Will Join CPP Lawsuit

Koster

Attorney General Chris Koster, who is running for governor, says he will join more than a dozen other states in suing the U.S. Environmental Protection Agency to challenge rules imposing targets on states to reduce carbon emissions.

The state's utilities, including Ameren Missouri, had urged Koster to join the mostly Republican-led states fighting the rules. Koster, the only Democrat in the state's governor's race, has sued EPA over other recent regulations, including the controversial "Waters of the United States" rule strongly opposed by large agricultural interests.

Koster made the announcement during a speech at a meeting of rural electric cooperative members in Branson. He argued that the state's businesses rely on lower-cost energy and that costs would rise under EPA's rules, which would force the state to shift its heavy reliance on coal power to renewables and natural gas.

More: *St Louis Post-Dispatch*

MONTANA

PSC Cuts NorthWestern's Ability to Raise Rates to Make Up for EE

The Public Service Commission voted 5-0 to rescind a mechanism that had allowed NorthWestern Energy to raise rates to make up for demand lost because of energy efficiency programs. Commissioner Roger Koopman called the Lost Revenue Adjustment Mechanism "one of the worst ideas policymakers have ever come up with."

Commissioner Kirk Bushman said, "It just doesn't make sense for public policy to allow an electric company to encourage their customers to save money on their monthly bill by conserving energy, and then turn around and increase electricity rates on everybody to recover that lost revenue."

The PSC ruling will reduce NorthWestern's collections from state customers by about $12.7 million next year. The policy was put into effect in 2005 to compensate NorthWestern for reduced sales attributed to state mandated energy conservation programs.

More: *Associated Press*

NEW HAMPSHIRE

Committee Seeks Evaluation Revisions

A legislative committee instructed the Site Evaluation Committee, the state body responsible for issuing certificates to energy facilities, to revise key sections of its proposed rules for new projects such as the Northern Pass transmission line and the Kinder Morgan natural gas pipeline.

The legislators worked for three years with stakeholders to develop the new rules, which are opposed by energy industry and business representatives and generally supported by the environmental community.

But it's still unclear if the Site Evaluation Committee will impose the new rules on the Northern Pass transmission project or the Kinder Morgan Northeast Energy Direct pipeline along the state's southern boundary, according to Pamela Monroe, the committee's administrator. Both projects have attracted opposition.

More: *New Hampshire Union Leader*

NEW JERSEY

Offshore Wind Power Firm Regroups to Win Project

Fishermen's Energy, a firm that wants to put five windmills about 3 miles off the coast of Atlantic City, will cut ties with its Chinese turbine partner and revamp its plan after learning that the state Supreme Court won't hear its appeal of regulators' numerous rejections.

Instead of using turbines from the Xiangtan Electric Manufacturing Group, whose financial condition did not meet regulators' standards, the company will build a demonstration facility using turbines from German manufacturer Siemens.

The U.S. Department of Energy pledged up to $47 million for the project in May 2014, but the Board of Public Utilities declined to approve it, saying the project would need at least $100 million in federal subsidies to proceed. The wind farm, which developers are promoting as a pilot project, would generate an estimated 25 MW of power.

More: *Associated Press*

NEW MEXICO

Commission Hearing for San Juan Plant Begins

The Public Regulation Commission last week began a protracted hearing on the future of the coal-fired San Juan Generating Station. The hearing, which could last up to two weeks, will examine an agreement that plant co-owner and operator Public Service Company of New Mexico (PNM) signed in August with environmental groups, the Attorney General's office and the commission's staff. The agreement would shut down

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two of the plant's four generating units.

The agreement provides for a new PRC review of San Juan in 2018 to determine whether the remaining two units should be shut down after 2022, when the current partnership among plant co-owners expires and PNM's coal supply contract ends. PNM also agreed to lower ratepayer costs for nuclear energy to replace lost coal generation and to support more renewable energy development.

New Energy Economy, an environmental pressure group, is opposed to the agreement and advocates the immediate closure of more San Juan units and the procurement of more solar and wind generation.

More: *Albuquerque Journal*

NEW YORK

Long Island Solar Energy Booming

Installations of new residential and commercial solar systems on Long Island in 2015 are set to eclipse sales of the previous eight years combined.

The market has been driven by falling system prices, an influx of aggressive national leasing companies, generous state and federal subsidies, and frustration with Long Island's high electricity rates that are set to rise again next year, experts say.

The growth of solar is "staggering," said Carlo Lanza, chairman of the Long Island Solar Energy Industry Association, a business group. Local solar employment has almost doubled in two years, to at least 2,500 workers, the group estimates. "What we always dreamed of seeing happen here is coming to fruition," Lanza said.

More: *Newsday*

NORTH CAROLINA

Duke Disputes 'Tenacious' Solar Opponent Label

An environmental group says Duke Energy's gains in solar energy come at the expense of competing producers who want to participate in the solar revolution.

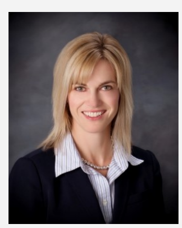
Duke says it has helped elevate the state to become the nation's No. 4 producer of solar power and is installing photovoltaic facilities in a number of other states. But an advocacy group says Duke has worked with lawmakers to try to reduce subsidies for competing private solar projects.

Environment North Carolina, in a report titled "Blocking the Sun," charges that Duke's support of solar "only extends … to solar panels the utility owns and that deliver profits to its balance sheet." A Duke spokesman dismissed the report as a "rehash of a lot of previous anti-utility reports and news accounts."

More: *Charlotte Business Journal; Duke Energy*

NORTH DAKOTA

PSC Reports the Use Of Renewables Rising



Fedorchak

Public Service Commission Chairman Julie Fedorchak reported last week that more than 16% of the retail electricity sold in the state in 2014 came from renewable sources (2.6 million MWh out of 16 million MWh).

The state exported more than half of the 36 million MWh of electricity it produced in 2014, which included about 27 million MWh of coal-fired energy and 8.8 million MWh of renewable energy, mostly wind power. Fedorchak said the state's carbon dioxide emissions have dropped by more than 15% since 2002.

The PSC filed comments opposing the U.S. Environmental Protection Agency's proposed Clean Power Plan, saying the rule is uneconomic, uses unrealistic assumptions and violates the Federal Power Act that gives states decision-making authority over their power supply.

More: *North Dakota PSC*

VIRGINIA

Rare Salamander Could Derail Pipeline Route

The $5 billion Atlantic Coast Pipeline could be held up by 5 inches — the length of the Cow Knob salamander, which inhabits a protected area of the George Washington National Forest, in the path of the proposed project.

The salamander and its rocky, forested habitat are protected under a federal pact struck in 1994 aimed at maintaining the amphibian's numbers so that it wouldn't wind up on the endangered species list.

Currently, 5.5 miles of the 564-mile pipeline would run through the creatures' home. Lead project partner Dominion Resources said it is evaluating its options and plans to meet with forest officials to discuss how the sensitive habitat could be avoided.

More: *Culpeper Star Exponent*

WEST VIRGINIA

State to Woo Shale-Related Businesses

The state has joined Pennsylvania and Ohio in an agreement to work together to attract shale-related industry to the region, home to the most productive natural gas basins in the country, the Marcellus and Utica shales.

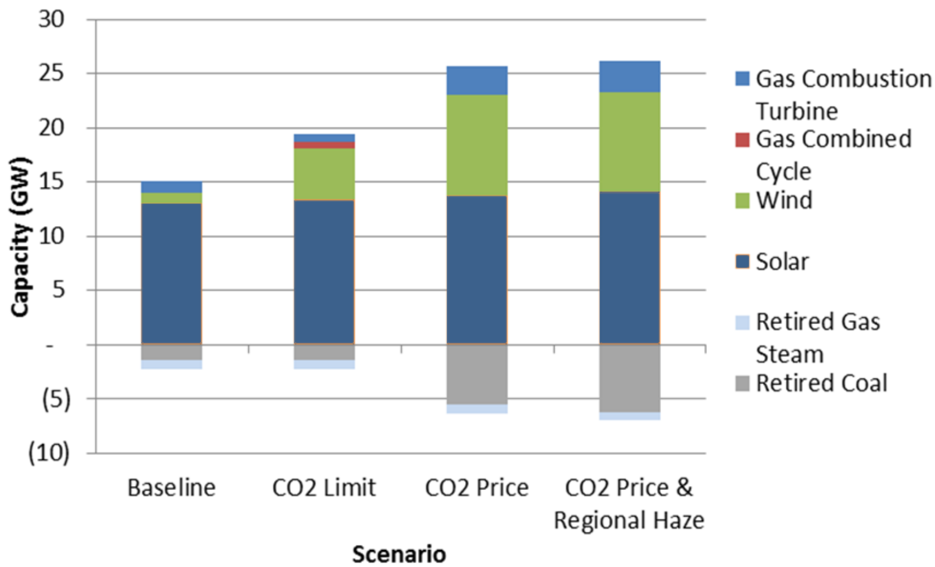
The effort was announced at a summit last week aimed at promoting cross-state efforts to woo manufacturers and petrochemical plants. The forum featured speakers who outlined focus areas such as interstate pipeline siting, public projects to store natural gas liquids and workforce training.

The states plan to bring together government, industry and economic development voices for more discussion.

More: *TribLive*

ERCOT Releases Updated CPP Analysis

By Tom Kleckner



Capacity additions and requirements by 2030 under Clean Power Plan scenarios. *Source: ERCOT*

ERCOT last week released an updated analysis of the Clean Power Plan's impacts on the Texas grid's reliability, saying the Environmental Protection Agency's final rule could result in the retirement of at least 4,000 MW of coal-fired generation, beginning as soon as 2022.

Warren Lasher, ERCOT's director of system planning, said while the 4,000 MW represents only 6 to 7% of the grid's total generation reserves, losing that capacity in too short of a timeframe would threaten the target reserve margin (13.75%).

"Coal retirements may happen sooner if owners have to make capital investments to comply with other plans," Lasher said, noting the current reserve margin is 16%. "One of our concerns is the potential for all the units to retire in too short period of time."

ERCOT said the changes could also increase retail power prices by up to 16% by 2030, based on an increase in the marginal price indicator. That doesn't include the costs of new transmission projects or other investments that could be needed to support compliance.

"Unit retirements may lead to reduced reliability of the system in localized areas, as new transmission lines will be needed to connect customers to new generating," Lasher said, noting it takes about five years to build transmission lines in Texas.

ERCOT's analysis considers the CPP's effects based on mass-based approaches to achieve the region's emissions targets by modeling four scenarios:

- Baseline: reflects current trends in the ERCOT region and market while considering announced retirements and current regulatory requirements;
- CO_2 limit: considers a system limit on emissions that allows the model to select the lowest-cost resource option without regard to market design or other considerations associated with implementation;
- CO_2 price: estimates a price for CO_2 emissions that would cause the ERCOT region to achieve the compliance targets; and
- CO_2 price/regional haze: also estimates a CO_2 price, but models the combined impacts of the CPP and the proposed Regional Haze Federal Implementation Plan within the ERCOT region as well.

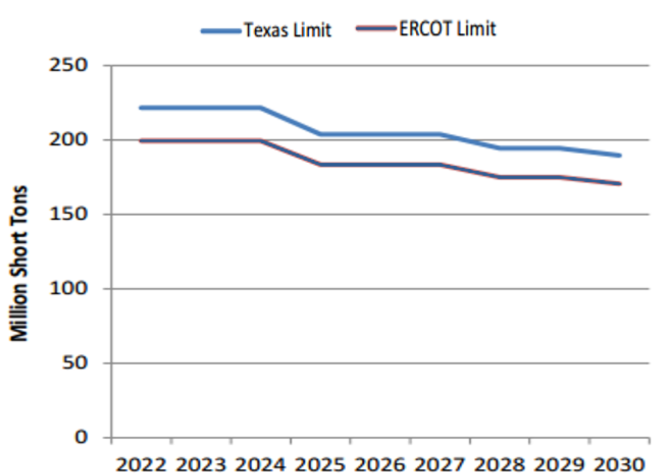
ERCOT's 4,000 MW of coal retirements would increase to about 4,700 when regional-haze requirements are taken into consideration.

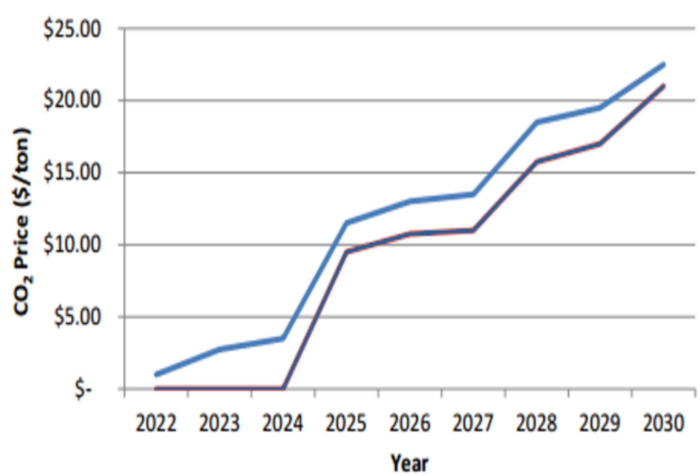
"ERCOT focused on high-level reliability concerns, consistent with our reliability role in Texas," Lasher said.

The scenarios that take into consideration a CO_2 price indicate more than 14,000 MW of utility-scale solar, 9,000 MW of wind capacity and nearly 3,000 MW of new gas-fired combustion turbines would have to be added to achieve compliance.

"Integrating intermittent renewables can be a challenge," Lasher said. "Increased storage capabilities on the system would increase its ability to integrate renewables … that would be an additional tool."

The ERCOT study only looks at the 85% of the state it is responsible for, leaving out East Texas, the Panhandle and El Paso areas.





ERCOT CO_2 limits, projected prices under Clean Power Plan. *Source: ERCOT*

SPP, MISO Reach Deal to End Transmission Dispute

Continued from page 1

Valley Authority, Associated Electric Cooperative, Louisville Gas and Electric, Kentucky Utilities and PowerSouth Energy Cooperative — signed off with the two RTOs on the deal.

Moving forward, MISO's compensation of SPP and the independent transmission owners will be determined through application of a capacity factor for flows exceeding the existing 1,000-MW contract path. New directional transfer limits were included in the deal: Power flowing from north to south is limited to 3,000 MW, while power flowing south to north is capped at 2,500 MW. Otherwise, the capacity usage provision between MISO and SPP under their joint operating agreement stands intact.

Under the settlement, MISO will pay SPP and the independent transmission owners $16 million — $8 million per year — to settle all claims of compensation from Jan. 29, 2014, to Jan. 31, 2016. Sixty percent of the funds will be paid to SPP, while the remaining 40% will be disbursed to the independent transmission owners. SPP said it will distribute the funds it collects to its members. The RTO will have to file the proposed distribution method with FERC because the funds are not being collected under its Tariff. (See related story, *Members Discuss Revenue Distribution from MISO Settlement*, p.18.)

The settlement creates an operating committee to manage any disputes that may arise. The committee will be composed of two members each from MISO, SPP and the independent TOs.

The agreement will last seven years from the date of the initial complaint in January 2014. In early 2021, the parties will have the opportunity to give notice to terminate or revisit settlement provisions.

Jennifer Curran, MISO's vice president of system planning and seams coordination, said that the RTO will "continue to evaluate if there are … appropriate alternatives to the agreement," including expansion of its own grid to reduce the use of its neighbors' systems.

"That work will be ongoing to see if there could or would be appropriate transmission solutions," she said during a press conference.

In recognition of the limits of the 1,000-MW contract path, FERC on Thursday granted MISO a year-long extension on a waiver of Tariff provisions and North American Energy Standards Board rules on the processing of long-term firm transmission service requests (TSRs) between MISO South and MISO Midwest or PJM (ER14-2022-001). "A number of long-term TSRs remain in the queue that seek capacity from the MISO South region to non-contiguous geographic regions outside of MISO. MISO expects the number of these already-sold long-term TSRs to exceed the 1,000-MW threshold until 2019. MISO intends to honor fully these transmission commitments, but they make it very difficult for MISO to process adequately any additional long-term TSRs," MISO wrote in the waiver request.

The waiver relaxes processing, assessment and timing regulations on long-term TSRs. MISO said that without the waiver, it would be forced to deny the requests.

The waiver, which expired April 1, 2015, now lasts until April 1, 2016 or until the resolution of the dispute between MISO and SPP.

Curran said MISO will file with FERC to remove the hurdle rate.

"We're excited to have made this filing today. We think it's a good compromise. Most importantly, it provides us clarity," Curran said. "It took a lot of work across all parties."

David Kelley, SPP's director of interregional relations, said SPP's main objective was to protect the interests of its members. He called the settlement a "mutually beneficial agreement."

"Both sides weighed the risks of not settling and realized both parties were better off not litigating and reaching consensus instead. We had some uncertainty, too, for our members, with continued litigation," Kelley said.

FERC set the dispute for hearings and settlement negotiations in March 2014. The parties met for seven settlement conferences at the commission's offices in Washington.

MISO said the settlement will allow cost-effective energy delivery through continued shared use of the transmission system.

"We are pleased to have reached a resolution that provides electricity savings to consumers across the MISO region and brings clarity to our members and all stakeholders," MISO CEO John Bear said in a statement. "With the issue of capacity sharing behind us, we can now collectively return our full attention to the significant challenges facing the industry."

SPP CEO Nick Brown also praised the arrangement.

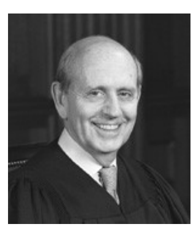
"As the SPP region grows and we continue to modernize the electric grid, cooperation with our neighboring regions has never been more important," Brown said in a statement. "I am pleased we were able to reach this agreement with MISO to ensure that our member companies and their customers are compensated for the use of the SPP transmission system."

FERC Jurisdiction over Demand Response in Peril as Supreme Court Splits

Continued from page 1

Breyer's Wife Sells Stock

Bloomberg reported that Alito recused himself because he owns stock in Johnson Controls, which owns EnergyConnect, a DR provider that has filed a brief with the court. Bloomberg also reported that Breyer's wife owned stock in the same company, which it said Breyer was unaware of when he heard the case. She sold her 750 shares for about $33,000 the following day after an inquiry by a Bloomberg reporter.



Breyer

FERC sought Supreme Court review because of the growing importance of DR. While the D.C. Circuit ruling explicitly addressed only DR participation in wholesale energy markets, FERC said the ruling also threatened its participation in wholesale capacity markets.

That could create upheaval in markets such as PJM, where capacity auctions represent about 95% of total DR revenue. After some uncertainty, PJM decided to include DR in the 2018/19 Base Residual Auction in August.

The Supreme Court agreed in May to reconsider the D.C. Circuit ruling on two questions:

- Whether FERC reasonably concluded that it has authority under the Federal Power Act, 16 U. S. C. 791a *et seq.*, to regulate the rules used by operators of wholesale electricity markets to pay for

Continued on page 36

FERC Jurisdiction over Demand Response in Peril as Supreme Court Splits

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reductions in electricity consumption and to recoup those payments through adjustments to wholesale rates.

- Whether the Court of Appeals erred in holding that Order 745 — which required RTOs and ISOs to pay DR the same LMPs as generation in energy markets — is "arbitrary and capricious."

(See *Supreme Court Agrees to Hear Demand Response Appeal*.)

Most of the arguments focused on jurisdiction, however.

Direct Effect


Verrilli

Verrilli led off the arguments and was interrupted almost immediately by Kennedy, who — after noting the interplay between retail and wholesale markets — asked what "marks the end of federal power and the beginning of local power?"

Verrilli did not answer directly, but contrasted the current dispute with the *Mississippi Power* case, in which FERC ruled that the utility could recover at wholesale its investment in a nuclear plant. The commission was overruled, with the court ruling that FERC had infringed on the authority of the state regulator to deny cost recovery in retail rates as imprudent. "That was a very direct effect on the exercise of state regulatory jurisdiction, which you do not have here," Verrilli said.


Scalia

"I find that a pretty fuzzy line, 'very direct effect,'" Scalia jumped in. He continued, "Yes, FERC has the power to regulate wholesale rates. But … the argument is, not through the fiddling around with retail rates, which is what is asserted is happening here."

$8 Hamburgers

After several exchanges between the two, Roberts took his turn with Verrilli, comparing FERC to someone "standing outside McDonald's" offering diners $5 not to go in and spend $3 on a hamburger.

Because of FERC's action, Roberts said, "the price of a hamburger is actually … $8, because if they give up the $5, they've still got to pay the $3. And your answer is, there's no impact on what the states can do, because they can still say, no, the price of the hamburger should be $2, or it should be $4. The point is that … FERC is directly affecting the retail price."


Kennedy

Kennedy returned with another question: "Is it fair to say that FERC is luring retail customers into the wholesale market? And if that … were true, would that not be a serious problem for the government?"

"It's wrong as a matter of history. It's wrong as a matter of law," Verrilli responded. "Wholesale demand response was not FERC's idea… This is a practice that grew up organically out of the private actions of market participants once the wholesale markets were deregulated. It's exactly the kind of innovative private market conduct that you would hope that deregulation would bring about. And the private actors, the wholesale market operators, brought that idea to FERC as early as 1999."

Verrilli went on, saying that the Federal Power Act gives FERC authority "over practices that affect … wholesale rates. And there's just no doubt … that all of the practices FERC is regulating occur in the wholesale auction."

Limiting Principle


Roberts

Roberts acknowledged that was true, but he pressed Verrilli to identify the "limiting principle" on FERC's authority, saying that without one, "FERC can do whatever it wants."

Verrilli responded that "the effects have to be direct."

Repeating hypothetical examples cited by the D.C. Circuit, he said, "regulating steel, regulating inputs into electric generation — we don't think FERC's authority goes anywhere near that far."

Verrilli concluded by citing the *Chevron* doctrine, which says FERC is entitled to deference in its interpretation of the Federal Power Act. "There is no statutory text that unambiguously denies FERC this authority that it's exercising here over this wholesale conduct."

Reliability Benefit


Phillips

Representing DR provider EnerNOC, attorney Carter G. Phillips backed Verrilli, saying that FERC did not create DR but rather responded to a market created by his clients and others who were trying to create a demand-side component to the wholesale market and a way to avoid brownouts. "And so tariffs were filed in order to provide a basis for putting in the demand side. And the reason why this is a direct effect on the … wholesale rates is because it's an absolute one-to-one relationship. If I put in a unit of — or reduce a unit of — demand, I don't need as much supply, and that affects the price directly. And that's the direct relationship that derives from the economic principles."

Phillips also sparred with Kennedy and Scalia. "FERC's argument is essentially circular," Kennedy said. "It says, well, the market forces will work this out — but we define the market."

Scalia asked Phillips why "all the companies" aren't in agreement with FERC and EnerNOC. DR provider EnergyConnect, the Coalition of MISO Transmission Customers and the PJM Industrial Customer Coalition joined EnerNOC's brief.

"Most of the private companies on the other side generate electricity" and see DR as competition, Phillips responded.

Clement, the final attorney to speak, made a point to note that he represented not only the generators that make up EPSA but also load-serving entities that could provide DR under state-sanctioned retail programs.

Signing on to EPSA's brief were the National Rural Electric Cooperative Association, the American Public Power Association, PPL and Old Dominion Electric Cooperative.

FERC Reducing Retail Demand?

"What FERC was trying to do here was to reduce retail demand by providing payments to retail customers on an otherwise wholesale market in an effort to change the

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FERC Jurisdiction over Demand Response in Peril as Supreme Court Splits

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effective price for retail sales," Clement said. "Now, that sure sounds like something that belongs to the states."

Sotomayor

"Where is that … written anywhere that that was their goal?" interrupted Sotomayor. "What I've heard them say is, we're trying to lower the price of wholesale [power] to a more just amount. That's what's in anything I've seen written. You've recharacterized it."

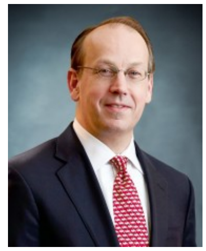
Clement persisted: "These retail customers don't belong on the wholesale market. Whether you think they were lured in or you think they walked in the door, it doesn't matter. They are in a market where they don't belong."

"What's the horror here of concurrent jurisdiction … if, in fact, it's lowering prices?" Sotomayor asked.

"You actually have the … federal regulators and the state regulators bidding against each other for the same customers to reduce their same retail demand," Clement responded.

LMP Too High?

That led Clement to move from the jurisdictional dispute to the second question, saying that while no states raised a jurisdictional objection before FERC itself, Ohio, Illinois and all of the MISO states said FERC should not require compensation at LMP "because that's too high."



Clement

"And by setting it so high, what you are going to do is you're going to crowd out our own efforts at dealing with demand response," Clement said for the states. "Because we love demand response. We want demand response. But we don't want to pay twice as much as the market really should pay for demand response. And if you're out there offering our same retail customers the ability to get demand response paid at huge LMP levels, then [states are] going to be crowded out."

Breyer said Clement's logic would prevent FERC from allowing large consumers to buy electricity at wholesale, "because that would take the retail customers away from the jurisdiction of the state."

He continued: "I have found no case … that would say that they cannot do this for the reason you suggest."

Kagan said Clement's argument seemed to be that FERC "can't do anything with respect to demand response."

Clement disagreed, saying FERC was allowed to have a role in "true wholesale demand response," which he said meant working through load-serving entities.

He said FERC's premise "that the sky will fall if you don't have this precise type of retail customer on wholesale market demand response" was belied by the experience of Southern Co., which does not participate in an RTO or an ISO, yet it has "a greater level of demand response than other parts of the country" subject to Order 745.

Congressional Intent

Kagan

Kagan said Clement's argument was at odds with the 2005 Energy Policy Act, "which made it so clear that Congress liked demand response — that it wanted FERC to lower barriers to demand response — to then say, well, FERC has no jurisdiction to do exactly what the policy that Congress articulated is."

Clement cited Commissioner Philip Moeller's dissent on Order 745 and comments by the Federal Trade Commission, which he said told FERC "you are picking the wrong compensation level."

Having saved five of his 20 minutes for closing remarks, Verrilli got the last word, saying Clements' view of "hermetically sealed-off retail and wholesale spheres" was unrealistic.

"In the real world today, large customers can buy directly. They can do it through contract, and they can also go into the wholesale market auctions and buy, if their states permit it… And this is really no different because demand response entities that want to come in and participate can only do so if their state law allows them to do so. So it's no different than what's been going on in the real world for quite a long time."

Verrilli also responded to Clements' arguments about the role of load-serving entities in providing DR. FERC "found that load-serving entities don't have sufficient incentives to engage in demand response. And it's obvious why they don't, because they cannibalize their own profits. The higher cost they have, the higher their rate-of-return profits are going to be generated. They will do it under commands from state regulatory agencies to do it, but they'll do it grudgingly. And what FERC said is you want people to come in who have a real profit motive to do it and that'll incent the LSEs to get in there and try to get a piece of the action rather than letting it go to somebody else."

Fears Unwarranted

Verrilli said fears that state and federal DR can't coexist were unwarranted, saying "we have 24 states in which this is going on. And if this were a problem, you'd expect to see in this administrative proceeding some evidence that it was a problem, and there is zero evidence. You look at all these briefs; there isn't a citation to anything in the administrative record that suggests that the federal and state programs can't work in harmony."

"You've got a practice … that has saved billions of dollars in wholesale costs and will save billions of dollars, and it's an effective tool against blackouts and brownouts, and that nobody has shown in the real world does any harm."

More: *Transcript of Argument*; *Briefs*

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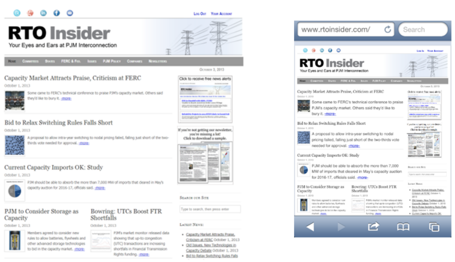

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MRC/MC Preview

7. ENERGY MARKET UP-LIFT SENIOR TASK FORCE (EMUSTF) Charter (11:00-11:10)

Members will be asked to approve the charter for the Energy Market Uplift Senior Task Force (EMUSTF). The MRC approved the creation of the task force in May to take a broad review of its method of providing Operating Reserve payments.

PJM said the changes were needed to reduce growing uplift costs resulting from Operating Reserves, "make whole" payments that ensure generators dispatched out of merit for system reliability don't operate at a loss.

See *PJM Proposes Operating Reserve Changes to Cut Uplift*

pjm — Energy Market Uplift Senior Task Force Charter — Draft

Mission

The Markets and Reliability Committee (MRC) approved the creation of the Energy Market Uplift Senior Task Force (EMUSTF) on May 30, 2013 to evaluate causes for energy market up-lift charges, develop ways to minimize them while maintaining prices that are consistent with operational reliability needs, and explore new methodologies for the allocation of make-whole payments.

PJM Proposes Operating Reserve Changes to Cut Uplift

April 30, 2013

PJM called Thursday for a broad review of its method of providing Operating Reserve payments, saying changes were needed to reduce growing uplift costs.

Operating Reserves are "make whole" payments that ensure generators dispatched out of merit for system reliability don't operate at a loss. Because they are collected through uplift charges and not reflected in day-ahead or real-time locational marginal prices, they cannot be hedged.

In 2012, operating reserve payments totaled a near record $649 million, 2.2% of total billing. Day-ahead operating reserve charges increased by about 90% in 2012, spiking in September after PJM increased the number of "must run" units dispatched in the day-ahead market.

- **Federal and state regulatory news briefs**

OHIO

Industry Likes Efficiency Rule, Wants Spending Cap

The Ohio Manufacturers Association favors the state's energy efficiency standards but wants a cap on how much utilities can charge for efficiency riders. The group said is still studying provisions of a bill that has been introduced to make changes in the program.

Meanwhile, wind energy supporters argued against a provision in the bill that would eliminate requirements that utilities buy a certain amount of in-state renewable energy.

More: *Columbus Business First; The Columbus Dispatch*

- **Voting summaries**

Trading Limits

Reason for Change: PJM proposed the cap because high bid volumes can make it difficult for the RTO's day-ahead markets software to reach solutions.

Impact: PJM can limit market participants to no more than 3,000 UTC transactions each in the day-ahead market when necessary for market operations. (A similar cap also applies to increment offers and decrement bids.)

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PJM will seek to set a limit on capacity imports before next year's Base Reliability Auction under a problem statement approved Thursday by the Planning Committee. -more-

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PJM's recommended Installed Reserve Margin (IRM) will increase slightly because of the increasing alignment of the RTO's peak demand with demand outside of the region, according to a preliminary analysis presented to the Planning Committee Thursday. -more-

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