RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

ISSN 2377-8016 : Volume 2016/Issue 48 December 20, 2016

EPA: Poor Fracking Practices Have Harmed Drinking Water

Data Gaps Make Quantification Impossible

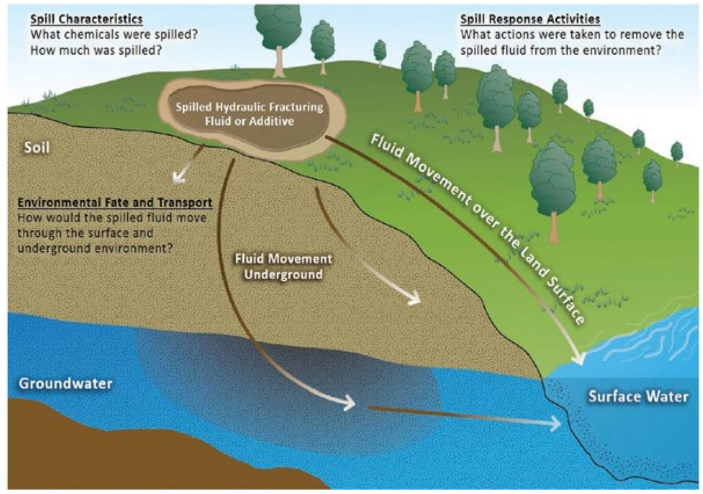
By Rich Heidorn Jr.

In a widely anticipated report, EPA said last week that fracking has harmed drinking water resources under some circumstances but that data gaps have made it impossible to quantify the scope of the problem.

The agency said it identified cases of impacts on drinking water at each stage in the fracking water cycle: acquiring water for use in fracking; mixing the water with chemical additives; injecting the water and chemicals into the production well to create and increase fractures; collecting wastewater after injection; and disposing or reusing wastewater.

"Impacts cited in the report generally occurred near hydraulically fractured oil and gas production wells and ranged in severity, from temporary changes in water quality to contamination that made private drinking water wells unusable," EPA said.

Continued on page 35



Generalized depiction of factors that influence whether spilled hydraulic fracturing fluids or additives reach drinking water resources, including spill characteristics, environmental fate and transport, and spill response activities. | *EPA*

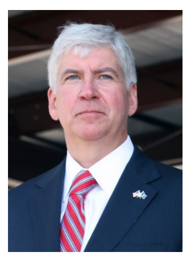
Michigan Energy Bill Preserves RPS, 10% Retail-Choice Cap

'Backup Plan,' IRPs Respond to Capacity Concerns

By Amanda Durish Cook and Rich Heidorn Jr.

Following a dramatic all-night session, Michigan lawmakers Thursday approved legislation that increases the state's renewable portfolio standard, preserves its limited retail choice and assigns state regulators to referee battles over net metering and capacity charges.

Gov. Rick Snyder, who had been pushing revisions to the state energy policies since 2015, personally helped broker a compromise over retail choice, meeting with legislators overnight into early Thursday morning, then shaking hands on the Senate floor after its members voted 33-4 for the package (SB 437, SB438). The House approved the bills 79-28 and 76-31 earlier Thursday afternoon, the last day of the state's two-year legislative session. (See *Michigan Senate Increases RPS; Keeps 10% Retail Choice Cap*.)



Snyder

The first major change in Michigan energy

Continued on page 32

ERCOT Sees Increased Load Growth, Shrinking Reserves

By Tom Kleckner

ERCOT's electricity demand continues to grow more rapidly than expected, and while reserve margins are projected to shrink slightly, the Texas ISO says it still has sufficient capacity to support system reliability.

"Based on the information we have today and current planning criteria, we continue to see sufficient planning reserve margins through most of the 10-year planning horizon," ERCOT's senior director of system planning, Warren Lasher, said Thursday.

Continued on page 11

Also in this issue:

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

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

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

Contributing Editors
Ted Caddell 434-882-5589
Julie Gromer 215-869-6969

Production Editor
Michael Brooks 301-922-7687

MISO Correspondent
Amanda Durish Cook 810-288-1847

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

CAISO/West Correspondent
Robert Mullin 503-715-6901

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

PJM Correspondent
Rory D. Sweeney 717-679-1638

Subscriptions and Advertising

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

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

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

Subscription Rates:

	PDF-Only	PDF & Web
Annually:	$1,500.00	$1,800.00
Quarterly:	315.00	400.00
Monthly:	125.00	150.00

See details and Subscriber Agreement at rtoinsider.com.

CAISO News

CPUC Orders Renegotiation of San Onofre Settlement

By Robert Mullin

The California Public Utilities Commission last week ordered Southern California Edison and San Diego Gas & Electric to meet with groups opposed to the commission's 2014 settlement that saddled ratepayers with 70% of the costs related to the premature closure of the San Onofre Nuclear Generating Station.

Commissioner Catherine Sandoval reopened the record on the proceeding in light of revelations that former CPUC President Michael Peevey engaged in persistent unreported *ex parte* communications with SCE during negotiations leading up to the $4.7 billion deal.

"The CPUC's rules require a level playing field by mandating *ex parte* disclosures for rate-setting proceedings, such as this one," Sandoval said in a statement. "The CPUC must ensure the integrity of its processes and that its decisions serve the public interest."

The CPUC urged the utilities to "carefully consider" changes to the agreement proposed by California's Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN) — both of which withdrew their support for the original deal when Peevey's activities became public after state investigators seized notes from his home showing that he discussed terms of the settlement with an SCE executive at a Warsaw, Poland, hotel. Peevey had previously served as president of the utility.

SCE expressed disappointment with the Dec. 13 ruling but said it will comply with the directive to meet with the other settling parties by Jan. 31. The utility said it continues to believe that the original settlement represents an "appropriate allocation" of costs.

"SCE has provided or will provide refunds and rate reductions of almost $1.6 billion under the settlement, and this amount may be increased by recoveries from Mitsubishi Heavy Industries, the supplier of the defective steam generators," the company said in a statement.

Among the modifications sought by TURN are the removal of some or all of the $2.17 billion in plant investment currently included in the rate base and a refund to ratepayers of costs related to the failed replacement steam generators that forced San Onofre's permanent closure.

TURN has also proposed that SCE eliminate $25 million in utility funding for greenhouse gas research at the University California-Los Angeles, a key outcome of the secret talks with Peevey.

Contending that "information has value, as does unequal access to decision-makers," ORA has proposed that SCE refund ratepayers $383 million for the "quantifiable loss" of ORA's litigation position — the difference between the settlement amount and what ORA says ratepayers would have negotiated if the agency had equal access to information. The agency is also recommending the utilities issue an additional $408 million in refunds.

The CPUC has set an April 28, 2017, deadline for the settling parties to reach an agreement to modify the original settlement. If no agreement is reached, individual parties will be asked to file a summary of their positions in order to inform further action by the commission.

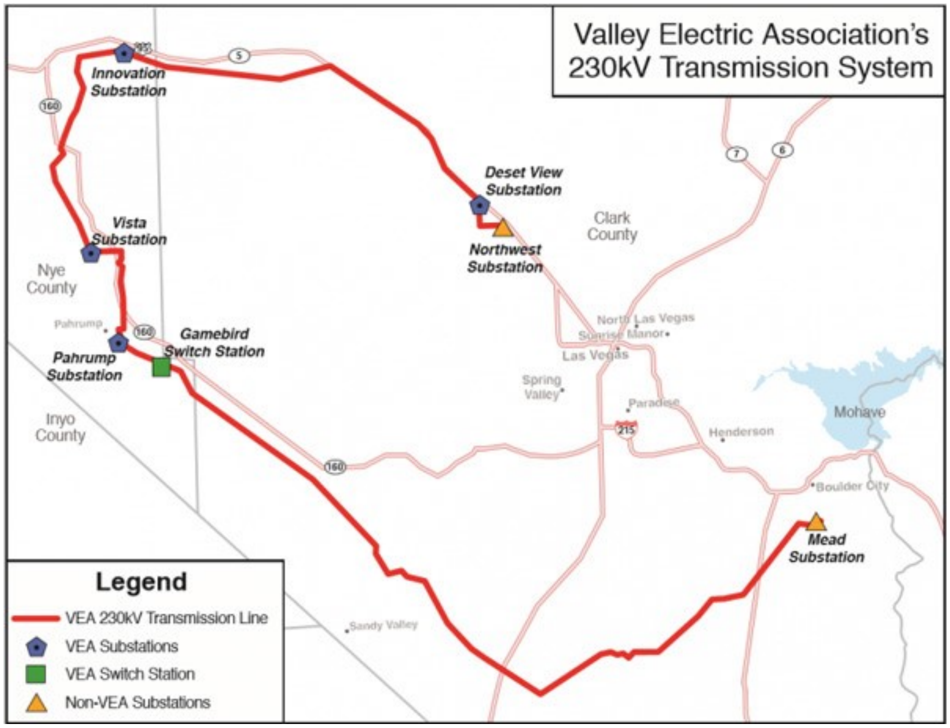
San Onofre was shut down in January 2012 after detection of a radiation leak from one of the plant's generating units. Operators soon discovered that the steam generators in both units on the site suffered from excess tube wear, despite having been replaced in 2009 and 2011 at a cost of $671 million. SCE decided to retire the plant in 2013.

Pharoah Construction

CAISO NEWS

CAISO Board Welcomes GridLiance Membership

By Robert Mullin



Valley Electric Association

GridLiance moved one step closer to joining CAISO as a participating transmission owner after the ISO's Board of Governors voted Dec. 15 to approve the company's membership.

The company is seeking to join the ISO after agreeing to purchase Valley Electric Association's 230-kV transmission network for more than $200 million. (See <u>*Valley Electric Approves Sale of 230-kV Network to GridLiance*</u>.)

Nevada-based Valley Electric is the ISO's only transmission-owning member outside California. The cooperative provides power to about 45,000 customers in a 6,800-square-mile service territory along the California-Nevada border.

The transmission assets being transferred include 164 miles of 230-kV lines linking Valley Electric's base in Pahrump, Nev., with both Las Vegas and the Mead substation — a major delivery point for power wheeled into California. Valley Electric completed the network in 2013 in order to improve reliability for its sprawling but sparsely populated service area.

As part of the deal, GridLiance has said it will reinforce the ISO's interconnection with Nevada's Eldorado substation, another major wheeling point into California.

Valley Electric saw the value of its network increase significantly after the co-op joined the ISO in 2013. It will recover about 2.4 times its investment.

Chicago-based GridLiance acknowledged that it is paying top dollar for the assets, saying they will provide the company with a foothold in an area that bridges the California market with the interior West.

"We did pay a premium to enter this relationship," GridLiance CEO Ed Rahill told the CAISO board ahead of its vote. "And if you think about that, it's only because our commitment is so many decades into the future that it becomes insignificant."

Under the agreement, Valley Electric will still operate and maintain the system. The acquisition is not expected to affect the co-op's distribution system.

"Our relationship with Valley is going to continue as a long-term partnership to help the region and the community through economic development and energy projects that benefit not just Valley but the California ISO and California," Rahill said.

Valley Electric CEO Thomas Husted said the co-op joined the ISO because it is a "strong proponent" of regionalization.

"The sale of those assets does not change that position," Husted said. "We will continue to be a load-serving entity and a [participating transmission owner] within the California ISO."

Husted said the network was built to serve Valley Electric's load, provide reliability and foster development of renewable assets that will continue to support regionalization.

"That [regionalization] now is growing beyond Valley Electric's original mission and beyond our charter," Husted said.

The board's approval is conditioned on GridLiance executing a transmission control agreement with the ISO and FERC accepting the company's transmission owner tariff and revenue requirement.

GridLiance would be the 17th transmission owner to join the ISO.

Launched in March 2015 with backing from the Blackstone Group, GridLiance bills itself as the nation's first competitive transmission company focused on collaborating with public power entities. It made its first two acquisitions — 420 miles of 69-kV and 115-kV lines in Missouri and Oklahoma — a year ago. (See <u>*GridLiance Makes First Acquisitions*</u>.)

> **"We did pay a premium to enter this relationship. And if you think about that, it's only because our commitment is so many decades into the future that it becomes insignificant."**
>
> **Ed Rahill, GridLiance**

CAISO News

Seattle City Light Signs EIM Membership Agreement

By Robert Mullin

Seattle City Light has signed an agreement with CAISO to begin participating in the Western Energy Imbalance Market (EIM) in April 2019.

"Seattle City Light has preliminarily evaluated the Energy Imbalance Market from an environmental, commercial and reliability perspective, and I believe City Light's participation can deliver benefits to our customers in all three areas," City Light General Manager Larry Weis said in a statement.

Weis said City Light's participation in the EIM would represent the best use of the utility's resources and expertise to support "a clean energy economy" throughout the West.

"This is the first in a number of steps to better integrate large-scale renewable resources in the West, and a new tool in our 'tool belt' to address climate change and set the foundation for a cleaner energy future," Weis said.

With a generating portfolio heavy in hydroelectric resources, City Light stands to benefit from the EIM as an exporter of the flexible ramping capability needed to smooth out intermittent renewables.

City Light's participation will ultimately be contingent on satisfying concerns of Seattle City Council members who have asked for a more thorough accounting of the costs and benefits of market membership. (See *Council OKs Seattle City Light Bid to Explore Joining the EIM*.)

In order to support a decision to join the market, Seattle lawmakers have asked City Light to flesh out the findings of an EIM benefits study performed by consulting firm E3 that showed the utility could earn an additional $4 million to $23 million in yearly revenues from the market. Council members Lorena González and Mike O'Brien expressed concerns about the estimated $8.8 million in upfront costs for joining the market and the uncertainty around revenue projections.

"We will continuously evaluate the financial impact of participation in the Energy Imbalance Market," City Light spokesman Scott Thomsen told *RTO Insider*. "If at any time we find that participation would not be in the best interests of Seattle City Light's customer-owners, we can walk away from the agreement with CAISO at no cost."

The utility is required to report its updated determinations to the council's Energy and Environment Committee by April 10, 2017.

City Light would become the seventh balancing authority area to join the market after the entry of Portland General Electric in October 2017 and Idaho Power in April 2018.

It would also likely be the first publicly owned utility to participate in the EIM, although its entry could coincide with that of the Sacramento Municipal Utility District. SMUD announced its intent to join the market September and is expected to sign an implementation agreement early next year, according to Jim Shetler, general manager of the Balancing Authority of Northern California, of which the utility is the largest member. (See *SMUD to Join EIM in Spring 2019 at the Earliest*.)

CAISO News

CAISO Board OKs Metering, EIM Governance

By Robert Mullin

The Western Energy Imbalance Market featured prominently in two proposals approved by the CAISO Board of Governors during its Dec. 15 meeting.

One measure will enable more CAISO market participants to meter their own resource performance data and submit it to the ISO for billing. The measure was proposed largely to help reduce costs for participating in the ISO's markets, according to a CAISO memo to the board.

"Metering is a significant cost for market participants both in our base market and the Western Energy Imbalance Market," CAISO CEO Steve Berberich said. "Our goal is to reduce the barriers of entry to [the EIM], and metering is part of that."

CAISO currently obtains settlement-quality meter data through two different processes, depending on the type of resource. In one process, the ISO directly polls a resource's meter and performs the validation, estimation and editing procedures necessary to achieve settlement. In the other, a scheduling coordinator is authorized to perform those settlement functions itself and submit the results to the ISO.

The proposal approved by the board extends eligibility for scheduling coordinator metering to certain resources that are currently required to be metered by the ISO.

Eligibility will now be open to energy- or ancillary services-only generators, distributed energy resources operating under a participating generator agreement and "intraties" — links between two utility distribution company service areas that can function as a proxy resource for market purposes.

The change will allow market participants to avoid the costs associated with using a CAISO-approved meter, meter reprogramming, inspection by an authorized inspector and the telecommunications equipment needed for the ISO to poll the data.

Scheduling coordinators applying for self-metering will be required to submit a settlement-quality meter data plan for all resources they represent to ensure accuracy in settlements.

That provision will apply to all new resources entering the market, regardless of resource type. It will also cover any new ISO resources that were previously EIM resources not subject to the requirement.

But the data plan requirement will not apply to scheduling coordinator metered resources already operating in the market.

"Existing market participants will have no additional requirements imposed on them as a result of this proposal," said Tom Flynn, CAISO manager of infrastructure policy and development.

The measure also creates some uniformity in reporting by requiring all new generators in the ISO or EIM to submit meter data in five- or 15-minute intervals. Under current practice, ISO resources can choose break down their data submission into five-, 15- or 60-minute intervals, while EIM participants are restricted to five-minute reporting.

"For EIM participating generators, this represents a potential cost savings by avoiding the need to reprogram existing meters already capable of submitting meter data in 15-minute intervals," the ISO said.

Kristine Schmidt, chair of the EIM governing body, expressed appreciation for the ISO's revised approach to metering.

"This is very important for our EIM entities who have a significant number of meters that would otherwise have to be changed out," Schmidt said.

"This seems like a win-win all around," ISO board member Angelina Galiteva said in voting for the proposal. "This one is easy."

Guidance Document Approved

The board also voted to approve the EIM's "guidance document," a set of procedures outlining how ISO staff should interact with EIM representatives and participants. The document sets out the timeframes in which CAISO staff will notify the governing body about ISO initiatives and explains the processes by which governing body mem-

Continued on page 6

CAISO NEWS

CAISO Board Approves 2017 Budget with Steady Revenue Requirement

By Robert Mullin

CAISO's Board of Governors approved a 2017 budget that includes a $4.3 million increase in spending but no corresponding rise in the grid operator's revenue requirement.

"I do think it's worth pointing out that the board has been engaged in development and review" of the budget before the vote, CAISO CEO Steve Berberich said during the board's Dec. 15 meeting. "So it's really been an ongoing process. This is just the final step."

Although the ISO's total expenditures are set to increase by 2% to $214.5 million, the annual revenue requirement will remain unchanged at $195.3 million, 18% its 2003 peak and 3.5% under the current FERC-approved cap.

The reason: Next year's $4.6 million rise in labor expenses will be offset by expected revenues from other sources, including money earned from administering the Western Energy Imbalance Market (EIM). The EIM is projected to bring in $4.8 million for the ISO in 2017, compared with $2.5 million this year.

The ISO's revenue requirement consists of five components, including operations and maintenance, debt service, cash-funded capital, an operation cost adjustment from the previous year and other costs and revenues. Those additional revenues are collected through EIM administrative charges and fees assessed for intermittent resource forecasting and generator interconnections.

CAISO recovers its revenue requirement through grid management charges assessed to market participants based on their use of the transmission system to serve load or deliver exports. The charges are slated to increase slightly next year, with ISO transmission volumes projected to fall 2 TWh, to 240.7 TWh. The drop continues a decline in recent years that's due in part to a persistent drought, which has reduced the volume of water being moved across the state using a massive network of electrical pumps.

Revenue Requirement Components	2017 Budget	2016 Budget	Change
Operations & Maintenance Budget ($ millions)	**$173.6**	$169.3	$4.3
Debt Service, including 25% reserve ($ millions)	**16.9**	16.9	-
Cash Funded Capital ($ millions)	**24.0**	24.0	-
Other Costs and Revenues ($ millions)	**(13.3)**	(10.8)	(2.5)
Operating Costs Reserve Adjustment ($ millions)	**(5.9)**	(4.1)	(1.8)
Total Revenue Requirement	**$195.3**	$195.3	$ -
Transmission Volume (TWh)	**240.7**	242.7	(2.0)
Pro-forma bundled ($/MWh)	**$0.811**	$0.805	$0.006

Increased cash flow from other sources will allow CAISO to leave its 2017 revenue requirement unchanged from this year's level. | *CAISO*

Fixed fees related to market operations — such as inter-scheduling coordinator trade and congestion revenue rights fees — will remain unchanged.

Operations and maintenance constitutes about 80% of the ISO's budget at $173.6 million, up 2.6% because of rising labor costs, including merit pay and benefit increases for existing staff and the addition of seven new employees.

CFO Ryan Seghesio earlier this year told stakeholders that CAISO has held a "tough line" on headcount but that "stress points" in several departments necessitated additional hiring. (See *CAISO Sees Steady Revenue Requirement Despite Spending Rise*.)

The increased labor expenses will be partially offset by decreased costs from vacating the ISO's Alhambra leased site, as well as declining outlays for consulting and contract staff.

Debt service costs will hold steady at $16.9 million. Construction of the ISO's headquarters accounts for most of the debt, according to April Gordon, the ISO's manager for budgeting and planning. Debt costs remain well below the 2006 peak of more than $80 million.

CAISO estimates it will spend $20 million on capital projects next year, most of them related to technology upgrades to support existing and new market operations.

Any minor year-end adjustments to the O&M budget made after the board's approval will not affect the final approved budget, the ISO said.

CAISO Board OKs Metering, EIM Governance

Continued from page 5

bers and EIM participants can provide feedback on proposed policy changes that affect the market.

"What the guidance document does is take all those rules — and establishes a process for implementing them," said Dan Shonkwiler, CAISO general counsel.

Most significantly, the document provides solutions to the overlapping authority between the ISO board and the EIM governing body resulting from the EIM's delegation of a portion of its authority over Federal Power Act Section 205 filings to the ISO. (See *EIM Leaders OK Governance 'Guidance' Proposal*.)

While the EIM governing body voted earlier this month to approve the guidance document, CAISO's Tariff requires the board to formally approve any proposals — including those solely affecting the EIM — that alter the Tariff.

"I think this is an important step forward," board member David Olsen said. "It really helps to clarify the scope of responsibility of the EIM board."

ERCOT NEWS

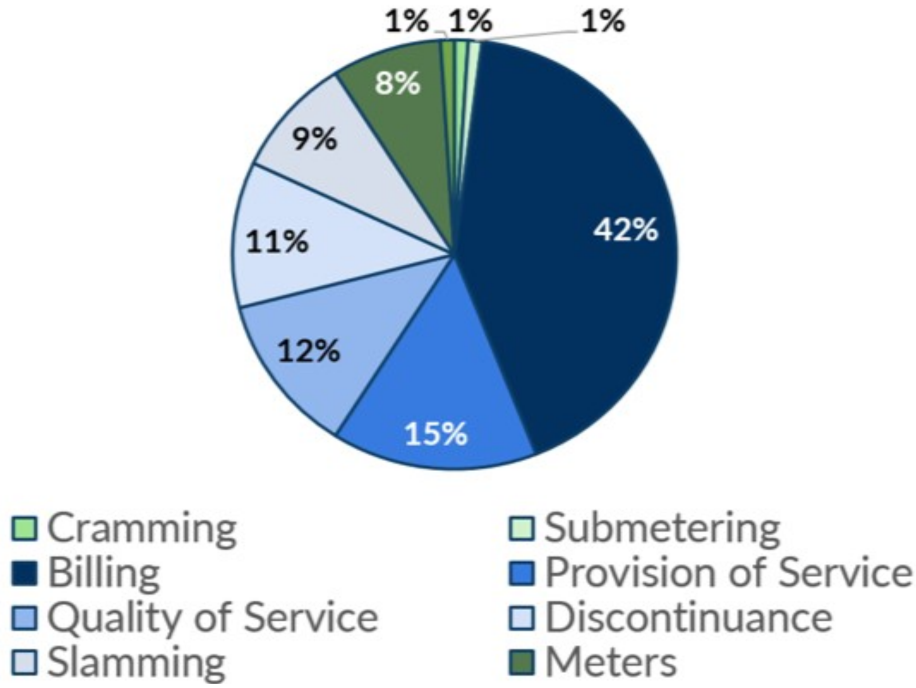
Texas PUC OKs Distributed Generation Rulemaking, Competition, Rate Reports

By Tom Kleckner

The Public Utility Commission of Texas wrapped up its 2016 open meeting schedule Friday by approving a rulemaking on interconnection agreements (IAs) for distributed generation and reports on electric market competition and alternative ratemaking mechanisms.

The distributed generation order allows the end-use DG customer to either be a party to the agreement or the "non-utility" party as the owner of the facility, the facility's premises or the produced energy (No. 45078). The commissioners said they would have jurisdiction over IAs, but not over "any disputes between an end-use customer and a non-utility signatory to the IA."

Chairman Donna Nelson dissented from the order. She had expressed concerns last month over the PUC's inability to help solar energy customers seeking redress from the commission over potential "bad actors."



Electric complaints received by category, September 2014-August 2016 | *ERCOT*

2017 Competition Report

The PUC approved its "2017 Report on the Scope of Competition in Electric Markets in Texas" (No. 45635), accepting Commissioner Ken Anderson's suggestion that the report repeat previous recommendations to the Texas Legislature calling for:

- The repeal of state law establishing natural gas as "the preferential fuel" for electricity generation and creating natural gas energy trading credits. "Because natural gas-fueled facilities have been the most commonly built new generation in Texas for many years and are expected to continue to be, there is no need to establish incentives for natural gas generation," the report says.
- The repeal of state law requiring the installation of 5,880 MW of renewable energy by 2015, a mandate that was met in 2008.
- Authorization for the PUC to issue advisory opinions on electric industry issues. "Providing clarification to a company concerning issues such as the purchase of assets or the acquisition of another company could allow it to avoid expensive regulatory proceedings, without impairing the commission's authority," the report says.
- Authorization for the PUC to use outside consultants, auditors, engineers or attorneys to represent the state before ERCOT, as it is currently permitted to do in FERC proceedings.

The commission also approved its report on alternative ratemaking mechanisms, which concludes that the current ratemaking system is not "in need of major revision" and that periodic rate proceedings using "streamlined recovery mechanisms" is "an efficient and effective way to ensure that electric rates are just and reasonable" (No. 46046).

The report does suggest the Legislature address concerns about vertically integrated utilities operating outside the ERCOT service area, whose key financial metrics "have lagged in comparison to those of the ERCOT utility companies," with reported rates of return consistently falling below PUC-authorized levels. The report says the utilities' returns have been hampered by "regulatory lag" in recovering capital investments.

Both reports will be sent to the Legislature, which convenes Jan. 10.

TDU Service Territory	Last Regulated Rate (2011), cents/kWh	Last Regulated Rate Adjusted for Inflation	Current Lowest Fixed Price	Percent Change
AEP Central	9.6	13.1	5.6	-57.25%
AEP North	10.0	13.6	5.0	-63.24%
CenterPoint	10.4	14.1	5.4	-61.7%
Oncor	9.7	13.2	4.5	-65.91%
TNMP	10.6	14.4	5.0	-65.28%

Inflation-adjusted comparison of residential regulated and competitive rates | *ERCOT*

ERCOT NEWS

ERCOT Board/Annual Membership Meeting Briefs

ISO Celebrates Milestones with Key Figures from the Past

AUSTIN, Texas — ERCOT celebrated a trio of memorable anniversaries Tuesday by getting part of the band back together for its Annual Membership Meeting.

ERCOT, which became the first ISO in the U.S. 20 years ago, also marked its 15th anniversary as the single control area for the state's competitive market and the 75th anniversary of the Texas Interconnected System, when the state's utilities banded together to ship power to the shipyards and refineries on the Gulf Coast during World War II.

"We remain the only independent, state-controlled system operator," ERCOT CEO Bill Magness told the membership, "and we like it that way."

To mark the occasion, ERCOT unveiled a historical video and brought back its first Board of Directors chairman, former Oncor president Mike Greene, to introduce one of the primary architects of the state's electric restructuring bill as the meeting's guest speaker. Steve Wolens, a retired 12-term Democratic state representative, worked with Republican State Sen. David Sibley to push Senate Bill 7 through the Texas Legislature in 1999 against only four opposing votes.

Greene name-dropped former Texas PUC commissioner and current ERCOT Director Judy Walsh, former FERC and PUC commissioner Pat Wood and others from the past before eventually introducing Wolens.

"My role has been reversed. I'm standing at the microphone, and Steve is in the audience wondering what I'm going to say," Greene said, before taking a pause. "I'm actually starting to enjoy this."

"It's an honor to be back," said Wolens, pegged by *Texas Monthly* in 1999 as the "Intellectual Gladiator" for his legislative work. The magazine noted Wolens "produced an electricity deregulation bill that won the support of consumers, environmentalists and utilities." When the bill passed, Wolens' colleagues honored him with a standing ovation.

Wolens, who also led a push to reform ethics laws before retiring from the Legislature in 2005, was recently named by Texas House Speaker Joe Straus to serve on the Texas Ethics Commission. His term will last until November 2019.

Recounting SB7's history, Wolens said "there was no reason to restructure in the 90s," given Texas had the lowest electric rates in the country. However, the state also had some of the highest bills ($1,064 annually for the average residential customer, he said) and a reserve margin that was predicted to drop below 8% by 2004.

"And here we were in Texas, boasting about the state and boasting about our growth."

Wolens said the inability to get energy companies to invest and Ohio-based American Electric Power's announcement that it would acquire Dallas-based Central and South West Corp. in 1997 gave the restructuring legislation a boost.


Steve Wolens addresses ERCOT's Annual Membership Meeting | © *RTO Insider*

"We had to bring more certainty, more reliability to the market," he said. "Our goal was to reduce the risk to private investment and do whatever we could to keep the local companies we had."

The key to SB7 was its price-to-beat (PTB) measure, Wolens said. The bill required incumbent utilities to take a 6% rate cut and hold that for three years, or until they lost 40% of their previously regulated market share.

This was to discourage what Texas had seen in other restructured markets, Wolens said. "We had seen it all," he said, referring to trucking, banking and airline deregulation. "Once you deregulate, the incumbent in that particular industry, the powerful player, cuts rates and drives everyone else out of business. The three years allowed new competitors to come in."

And that's exactly what happened in the ERCOT market. Wolens noted nearly 200 residential retail electric providers currently operate in the state, offering in his estimation some 2,000 plans to choose from. The ERCOT market will record its lowest average energy prices this year ($24.64/MWh) since the market opened ($25.64/MWh in 2002).

"The PTB was the DNA of the entire bill," Wolens said.

SB7 and the ensuing $7 billion Competitive Renewable Energy Zone transmission project, which connected windy West Texas with the growing urban population centers to the east, has given the state almost 18,000 MW of installed wind capacity. If the Lone Star State were its own country, it would rank sixth in the world in wind capacity.

The Texas market is so strong, Wolens said, it will survive a future that may include the country's withdrawal from the Paris Agreement, the loss of wind and solar tax credits and "installing a climate denier" at EPA.

"All those issues aside, it's not going to make a difference because the market is vibrant," he said. "It's exactly what we hoped for in 1999."

Magness Celebrates ERCOT's Achievements

Magness listed ERCOT's 2016 achieve-

Continued on page 9

ERCOT NEWS

ERCOT Board/Annual Membership Meeting Briefs

ERCOT CEO Bill Magness addresses the Board of Directors. | © RTO Insider

Continued from page 8

ments before the luncheon began, including maintaining a reliable system and efficient market, upgrading the Energy Management System, revising the criteria for reliability-must-run studies, completing transmission improvements in the Rio Grande Valley and integrating wind generation.

The ERCOT market generated more than 15,000 MW of wind energy for the first time in 2016, setting a new record of 15,033 MW in November. It also recorded three new marks for wind penetration during the year, topping out at 48.28% of load in March.

Magness credited stakeholders' collaboration with staff and their forward thinking with making the records possible.

"We've always said if we can see it, we can integrate it," he said. "When we hit 15,000 MW of wind and high penetration levels, people asked, 'How do you do that? How is that possible?' It's possible because in ERCOT, when those things start to happen, we talk about it. That's the value of thinking ahead while still in real time."

ERCOT also set a new system peak (71,110 MW on Aug. 11), two monthly demand highs (during a warmer-than-normal September and October) and a new weekend peak (Aug. 7). The ISO's annual Capacity, Demand and Reserve report released Thursday foresees demand rising to more than 77,000 MW by the summer of 2021. (See related story, *ERCOT Sees Increased Load Growth, Shrinking Margins*, p.1.)

Increasing Demand Boosts Finances

The high demand in the fall means the ISO should go into 2017 — the second year of its two-year spending plan — with net revenues as much as $13 million above budget. Also helping ERCOT's finances are savings in resource management costs (primarily staffing management and project work), expected to come in $3.9 million under budget, and computer hardware purchases, at $1.9 million under budget.

"We challenged ourselves as a management team to maintaining some flexibility for ourselves, going into [the] second year," Magness said. "We're committed to keeping a flat [administrative] fee for at least two years. Keeping that budget discipline is going to be really important in maintaining that. One year in, we feel like we're in a pretty good place."

Magness also said ERCOT's "technology refresh" to update aging computer technology is well underway. The four-year project began in 2015 and is forecast to come in at or under its $48 million budget. Magness said 60% of the contracts are locked in place, with 21% of the hardware already deployed.

Board Passes Transmission Planning Change

The board easily passed the only contested revision request before it, a planning guide change revising the criteria used to determine the need for new transmission projects that faced some pushback at the Technical Advisory Committee earlier this month. (See *ERCOT Addresses Transmission Planning Challenges with New Rule*.)

Valero Services' Jack Durland, representing the Industrial Consumer sector, cast the lone dissenting vote. He questioned the planning guide revision request's (PGRR) "bounded higher of" load forecast methodology, in which ERCOT will compare its load forecast with the summed bus-level forecast for each weather zone, and the need for two additional staffers to work on the planning process.

"Does one size fit all the [ERCOT] regions?" Durland asked. "If it doesn't, we'll end up with constraints, specifically in Houston. We'd like to see maybe some backcasting to understand this higher boundary methodology actually does fit most scenarios."

PGRR042 defines considerations for selecting the most appropriate demand forecast in planning studies and how to model certain generation resources, such as mothballed units or those that can be also be connected outside the ERCOT region, in planning cases. It also describes how to incorporate new generation units in sensitivity analyses when they have interconnection agreements but have not met all the requirements to be included in transmission planning studies.

Warren Lasher, ERCOT's senior director of system planning, told the board the ISO will "grey box" the PGRR's language before formally codifying it for 2018. In the meantime, he promised staff would work closely with stakeholders throughout next year "to ensure we have an appropriate mechanism to make sure we have adequate transmission."

"We have been having discussions with stakeholders about doing backcasts for the forecasts in the planning working groups," Lasher said, "and we will continue to have those discussions … to make sure that the needs of customers, especially in the Houston region, and other regions of the state are met."

"I can tell you with confidence that we can move around folks," Magness said, addressing the staff additions. "Two [full-time employees], we can handle."

Magness reminded stakeholders that PGRR042 came from a Public Utility Commission of Texas request to re-evaluate ERCOT's planning process, part of the

Continued on page 10

ERCOT NEWS

ERCOT Board/Annual Membership Meeting Briefs

Continued from page 9

commission's approval order for the Houston Import Project, a $590 million initiative due to be completed by summer 2018.

"This planning guide became the vehicle for the analysis," he said. "Our folks feel comfortable they have sufficient flexibility and options for making sure the change works. It was a successful accommodation … of something we could work with, and we felt like folks in the market could work with, as well."

New Board, TAC Members Approved

The ERCOT board approved Calpine's Randy Jones and Source Power & Gas' John Werner as new members of the board for 2017. The two, who served as alternates last year, will represent the Independent Generator and Independent Retail Electric Provider segments, respectively.

Jones is switching places with E.ON Climate and Renewables' Kevin Gresham, while Werner replaces Direct Energy's Read Comstock.

The board has yet to fill the unaffiliated position vacated by Jorge Bermudez, who resigned from the board in October when his pending marriage created a conflict of interest. (See "ERCOT's Bermudez Resigns from Board Position," *ERCOT Briefs*.)

"We were distressed to find out you love someone more than us," joked Board Chair Craven Crowell, before presenting Bermudez with a resolution honoring his service.

The board also approved the Lower Colorado River Authority's John Dumas and Golden Spread Electric's Mike Wise (Cooperatives), SESCO's David Hastings (Independent Power Marketers) and Direct Energy's Sandra Morris and Noble Americas Energy Solution's Clint Sandidge (Independent Retail Electric Providers) as new TAC members.

Ancillary Service Changes, NPRRs Sail Through

The directors unanimously approved "very minimal" changes to the minimum ancillary service requirements, after two years of more substantial changes.

Staff limited its changes to regulation service. It proposed removing the exhaustion rate feedback metric from the regulation-procurement analysis, estimating five-minute net load variability by including solar generation and making annual updates to the 2013 General Electric study's tables reflecting incremental installed wind generation.

The board also unanimously approved a clean Statement on Standards for Attestation Engagements (SSAE) No. 16 audit report, modifications to forms ensuring the credit worthiness of market participants and five changes to the 2016 list of key performance indicators used to drive organizational performance.

The board consent agenda, which passed unanimously, listed eight nodal protocol revision requests (NPRRs):

- NPRR773: Broadens the scope of acceptable letter of credit issuers, allowing electric cooperatives to post letters from the National Rural Utilities Cooperative Finance Corp. with ERCOT.
- NPRR783: Revises a requirement for an independent audit to confirm the consistency of ERCOT operations models. The change is to comply with NERC reliability standard MOD-033-1 requiring a documented data-validation process for power flow and dynamic models.
- NPRR790: Adds phase angle equipment limitations to real-time monitoring, real-time assessments and operational planning analysis, as required by NERC standards. ERCOT will collect this information through the network operations modeling process.

Steve Wolens and Texas PUC Chair Donna Nelson renew their acquaintance. | © *RTO Insider*

- NPRR791: Clarifies the initial estimated liability (IEL) description to specify that it is based on estimated sales between qualified scheduling entities; restores the IEL for traders (inadvertently omitted from NPRR741) and corrects errors to the minimum-current exposure formula mistakenly overwritten by NPRR743.
- NPRR792: Aligns the nodal protocols with NERC's definition for special protection system (SPS) and uses "remedial action scheme" and "automatic mitigation plan" in place of SPS for consistency purposes, when applicable. The approval resulted in the TAC conducting an email vote on a related nodal operating guide request, NOGRR164, which was approved Thursday, 21-0.
- NPRR797: Creates a new report and display for the actual system load by forecast zone, similar to the capability for weather zones.
- NPRR801: Revises the physical responsive capability (PRC) calculation to include all load resources and align operating reserve demand curve (ORDC) reserves with the PRC change. It also aligns the ancillary service imbalance settlement with the change to the ORDC reserves.
- NPRR803: Removes un-codified language from NPRR439, which was approved four years ago to allow counterparties to increase their credit limit for the day-ahead market's current day.

"We were distressed to find out you love someone more than us."

Board Chair Craven Crowell to outgoing Director Jorge Bermudez

— Tom Kleckner

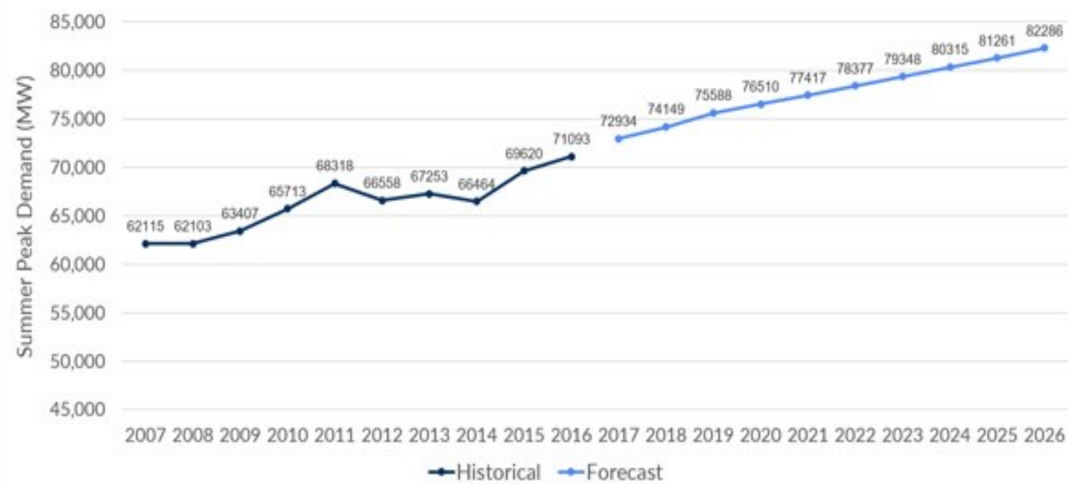
ERCOT NEWS

ERCOT Sees Increased Load Growth, Shrinking Reserves

Continued from page 1

The Texas grid operator's latest Capacity, Demand and Reserves (CDR) report, released last week, indicates next summer's peak demand will reach nearly 73,000 MW, growing to more than 77,000 MW by summer 2021. ERCOT set a new system peak this summer when it reached 71,110 MW on Aug. 11.

The ISO expects to have more than 82,000 MW of capacity available for next summer and more than 88,000 MW by summer 2021.



ERCOT summer peak demand | *ERCOT*

The increased load growth will cut the ISO's reserve margin to 16.9%, down from the May 2016 forecast of 18.2%. The CDR sees the reserve margin climbing to 10.2% in 2018 but dropping to 19% in 2021 — still well above ERCOT's 13.75% target.

ERCOT attributes the load growth to the state's strong economy, fueled by a rebounding petroleum market and high-tech jobs in Central Texas.

"We're seeing stronger growth than Moody's projected a year ago," said ERCOT Manager of Load Forecasting and Analysis Calvin Opheim. "Texas growth used to be tied to oil and gas and drilling. Those [industries] appear to be coming back alive, but when you come into Central Texas and San Antonio, a lot of people are moving here for well-paying jobs" in other industries.

Opheim said Moody's forecast for Central Texas, which ERCOT incorporates in its planning models, projects employment growth rates of more than 3% in 2021.

The Federal Reserve Bank of Texas is also optimistic, saying a stabilized energy sector, recent improvements in the manufacturing sector and increased optimism by Texas businesses will likely lead to a "moderately" improved economy in 2017.

ERCOT's demand in November 2016 was already up 11.2% compared to November 2015.

The new CDR shows almost 2,700 MW of new capacity since the May report, including 1,188 MW of wind and 262 MW of solar. ERCOT surpassed 500 MW of installed solar resources when a 160-MW project in West Texas was synched to the grid in November.

By next summer, the ISO expects to add nearly 3,000 MW of wind, more than 450 MW of solar and 2,660 MW of gas resources — more than 2,150 MW coming from two units near Houston and Fort Worth.

Planned resources reflect more than 10,000 MW of additional capacity by 2021.

The ISO's long-term forecast, which is updated annually, includes the addition of a new LNG facility being developed on the Gulf Coast, but it doesn't take into account Lubbock Power and Light's proposed migration of 430 MW of load from SPP to ERCOT.

> **"Texas growth used to be tied to oil and gas and drilling. Those [industries] appear to be coming back alive ... a lot of people are moving here for well-paying jobs."**
>
> **Calvin Opheim, ERCOT**

MISO NEWS

MISO Forward Auction Filing Draws Protests

By Amanda Durish Cook

MISO's proposed three-year forward auction in its retail-choice areas attracted more than 40 comments and protests, with critics calling the proposal costly and ill-conceived.

Executive Director of Market Services Jeff Bladen has said the proposal, which would take effect in the 2018/19 planning year, is designed to provide equally valued capacity from both merchant generators and regulated utilities (ER17-284). The comment period on the FERC filing closed last week; MISO expects a decision from the commission by March. (See *MISO Files Forward Capacity Auction Plan with FERC*.)

Among critics of the plan are MISO's Market Monitor, which says the auction, with a sloped demand curve for competitive retail areas, will not accurately represent the marginal value of capacity. "The proposal is highly likely to result in unstable prices that are either too low to retain existing supply that is needed or excessively high, attracting new resources that are not needed," Monitor David Patton said.

In his protest, Patton included a proposal for a two-stage prompt auction for FERC consideration. Competitive retail supply would still use a sloped demand curve and regulated utilities would use a vertical demand curve.

Premature?

The Illinois Office of Attorney General objected to the bifurcation of the capacity market. "By separating Illinois from the rest of MISO through the use of a three-year forward auction, as opposed to the prompt auction applicable to the remaining 90% of MISO load, Illinois consumers would pay higher prices for capacity," the office said.

Watchdog group Public Citizen said MISO did not have enough conversations with state lawmakers on their resource adequacy plans before making the filing, which he said will increase the cost to ratepayers. "This whole filing is a solution in search of a problem," Tyson Slocum, the group's energy program director, said in an interview. "That's the whole problem with holding stakeholder meetings, it's whoever shows up."

"At a minimum, FERC should suspend issuing an order in this docket until the legislative actions of Illinois and Michigan to address long-term resource adequacy can be independently analyzed and incorporated into this docket," Public Citizen wrote, referring to Illinois' financial support for Exelon's Clinton and Quad Cities nuclear plants and energy legislation approved by Michigan last week. (See *Illinois Lawmakers Clear Nuke Subsidy* and related story *Michigan Energy Bill Preserves RPS, 10% Retail-Choice Cap*, p.1.)

'Blind Faith'

The Coalition of MISO Transmission Customers and the Illinois Industrial Energy Consumers filed a joint protest asking FERC to reject the filing because MISO did not fully include the results of The Brattle Group's study, which the RTO relied on to justify the forward auction. The filing instead contained a MISO description of the study, demand curve diagrams, presentations made to MISO stakeholders by Brattle and testimony from three Brattle employees.

"The commission should not accept, on blind faith, that the Brattle study appropriately supports MISO's endeavors," the groups said. They also challenged Brattle's analysis as biased. Alliant Energy and others challenged MISO's reliance on the results of the OMS/MISO survey, which forecasts generation shortfalls in 2018. The company said the survey is not a "complete reflection of the future capacity needs in the MISO region."

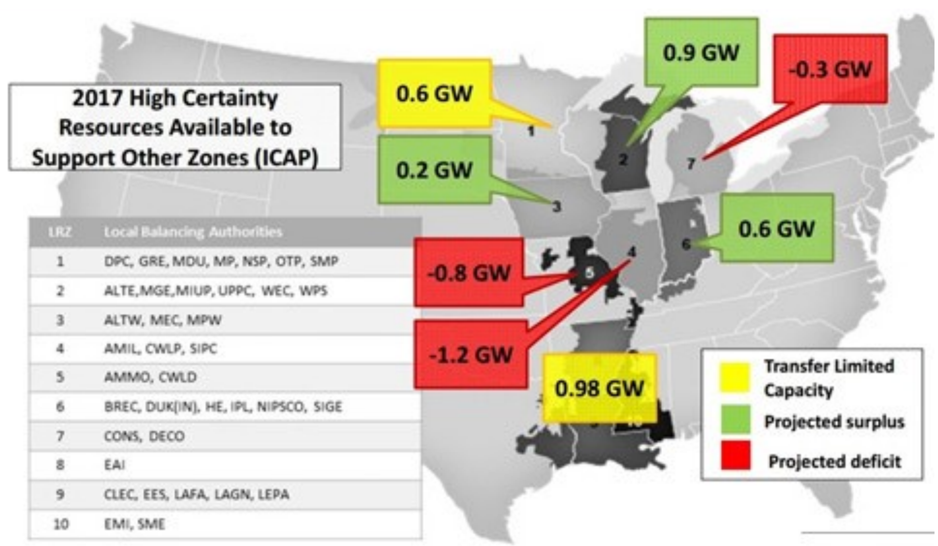
A group of transmission-dependent utilities in the Midwest — Madison Gas and Electric, Missouri Joint Municipal Electric Utility Commission, Midwest Municipal Transmission Group, Missouri River Energy Services and WPPI Energy — argued the proposal is "fraught with inconsistencies, errors and ambiguities" that could cause the provisions of the forward market to bleed into non-competitive areas. The group asked FERC to reject it.

Interference

Power marketer Direct Energy, which offers competitive natural gas plans for Michigan ratepayers in Consumers Energy and DTE Energy territory, objected to MISO's Tariff revisions to allow retail-choice states to opt out of capacity provisions via the auction design's prevailing state compensation mechanism. The company is challenging the filing on the basis it "impermissibly" interferes with wholesale markets.

Ron Carrier, Direct Energy's director of government and regulatory affairs, said he isn't sure if the limited amount of participating generation and load from retail choice areas would make the forward auction economic, although he said forward auctions in general "allow some price certainty into the future."

Continued on page 13



MISO, Organization of MISO States

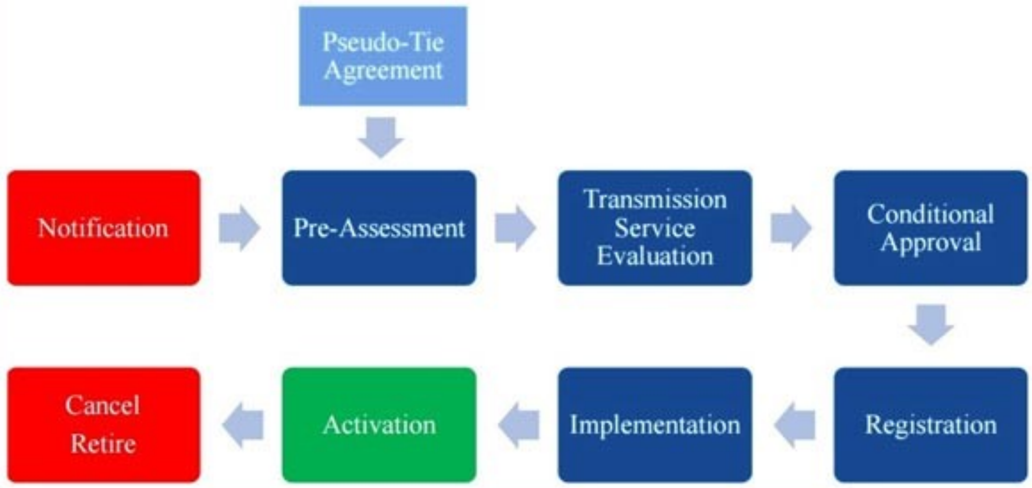
MISO News

MISO Stakeholders Narrowly Support New Pseudo-Tie Rules

By Amanda Durish Cook

MISO's Reliability Subcommittee last week narrowly approved a more stringent process for deciding on pseudo-tie requests.

The package, approved 5-4 with 13 abstentions at a Dec. 16 special meeting, includes a *pro forma* pseudo-tie agreement and Business Practices Manual language for generators that intend to sell their capacity or electricity outside the RTO's footprint.



Pseudo-tie implementation process | *MISO*

MISO plans to file the proposed rules with FERC in early January. But Senior Director of Regional Operations David Zwergel said the narrow vote and large number of abstentions could give the RTO pause and lead to more discussions to see if minor language changes could address opponents' concerns.

The new rules say proposed pseudo-ties can be rejected and existing pseudo-ties can be revoked if a market-to-market flowgate is not within 2% of MISO and the neighboring market's calculated generator-to-load distribution factor. (See *MISO Readies Updated Pseudo-Tie Rules*.)

Andy Witmeier, of MISO's operations division, said attaining RTOs — those using generators outside their borders — need to accurately calculate the impact that their pseudo-tied generation has on M2M flowgates.

The 2% provision, however, was a source of stakeholder confusion. Brian Garnett of Duke Energy said MISO had contradicted itself in the BPM language because in one instance, the RTO said the rules would not be retroactively applied, yet existing pseudo-ties could be subjected to the 2% rule. Amanda Schiro, manager of model engineering, said an existing pseudo-tie would only be subject to the 2% rule if it is modified, which would trigger a restudy under the new criteria.

Zwergel said he did not expect MISO to rescind any existing pseudo-ties based on the 2% threshold, but he said it wants to reserve the right in case an attaining RTO drastically changes its model and large discrepancies between models occur. Currently, pseudo-tie modeling in MISO is conducted four times per year, and Witmeier said the RTO's modeling occurs "within a few weeks of other RTOs."

WPPI Energy's Steve Leovy said he'd like to see a more stringent tolerance than MISO's proposed 2%, but RTO staff said they were confident with that threshold.

Stakeholders asked if MISO would include some of the pseudo-tie language in the MISO-PJM joint operating agreement. Ron Arness, senior manager of seams administration, said MISO could consider memorializing the changes in the JOA, but he did not see a need yet.

"It's something we could monitor if [MISO's and PJM's rules] don't align," Arness said. "Today we don't see any incompatibilities."

Entergy's Jeff Knighten, who cast an opposing vote, said his company agreed with a lot of details but "wasn't ready to sign off yet." Entergy said the 2% shift factor might work well "under test conditions," but RTOs might not be able to maintain the same accuracy "under transmission outage conditions which may result in a substantial change in system flows."

The other companies to provide public comments, NRG Energy and Occidental Chemical, likewise said details around the threshold were lacking and asked for justification.

MISO Forward Auction Filing Draws Protests

Continued from page 12

"Our main concern is the state shouldn't be granted authority over something FERC should have authority over," Carrier said.

MISO Transmission Owners said they had no opinion on the filing, but they asked FERC to make sure the RTO does not intrude on state jurisdiction over resource adequacy. They also asked FERC to require MISO to give annual reports that analyze the impact of the forward auction on the entire footprint for the next three years.

The Organization of MISO States also argued for protecting state jurisdiction, but the group took a step further, asking FERC to reaffirm the stance it took in a 2012 order that capacity markets are not necessary in vertically integrated areas (ER11-4081-001). "The [competitive retail solution] should not be viewed as the default means to maintain [resource adequacy] within retail-choice areas. It is imperative that state regulators maintain maximum flexibility and authority over the resource adequacy decisions within their jurisdiction," OMS wrote.

MISO NEWS

MISO Incorporates 1st Solar Farm into Wholesale Market

By Amanda Durish Cook

In a MISO first, the RTO has integrated a solar farm into its day-ahead and real-time markets.

North Star, a $180 million, 100-MW solar farm outside of Minneapolis, joined MISO's wholesale markets on Dec. 16. Xcel Energy will purchase power generated by the facility in a 25-year deal that helps the utility meet its 1.5% solar energy requirement in Minnesota.

The RTO said months of planning and testing went into the project to ensure a "smooth integration of solar power into MISO's day-ahead and real-time markets." MISO tapped forecasting firm Energy and Meteo Systems — the same firm already handling the RTO's wind forecasting — to forecast day-ahead solar.

"This project furthers the integration of renewable resources into our markets," said

North Star | *D.E. Shaw Renewable Investments*

Todd Ramey, MISO vice president of system operations.

MISO said that while several large-scale solar farms have been built in the footprint in the past few years, North Star is the largest in the Midwest, with more than 440,000 solar panels on 1,000 acres of former corn and soybean fields.

"Solar power from North Star is a key element in Xcel Energy's plan to deliver more than 60% carbon-free energy for our customers by 2030," said Chris Clark, president of Xcel Energy-Minnesota, North Dakota and South Dakota.

MISO filed the generator interconnection agreement between North Star and Xcel on Nov. 9 (ER17-329).

The solar facility is not allowed to exceed 100 MW. The project entered MISO's interconnection queue as a variable energy resource last September. MISO mandated about $2.2 million in network upgrades, including grading, two new 115-kV breakers and four 115-kV switches as a condition of the agreement. Xcel spent about $260,000 for interconnection facilities.

Xcel and project partners D.E. Shaw Renewable Investments and Community Energy Solar reported completing the project in mid-October after six months of construction.

MISO said this year that it has about 1,700 MW of solar generation at various stages of its interconnection queue.

PAC Briefs

Four Expedited Review Projects Under MISO Inspection

CARMEL, Ind. — MISO planners approved an expedited project request in northeast Arkansas and are evaluating three others in Michigan, officials told the Planning Advisory Committee last week.

The $3 million Hickman Central project, submitted by Arkansas Electric Cooperative Corp. in October, will include a new substation, a quarter-mile line to connect it to the Dell-Blytheville North 161-kV line and two 161/345-kV transformers, said Edin Habibovic, manager of expansion planning in MISO South.

The Little Rock-based cooperative said the improvements are needed by October 2017 to accommodate about 35 MW of new industrial load. It said getting approval under the 2017 Transmission Expansion Plan in December 2017 would be too late.

MISO recommended that AECC begin work on the project "as needed" to meet the in-service date in less than 10 months and said the project would be formally included in MTEP 17.

The RTO also received three expedited review requests from ITC Holdings' Michigan Electric Transmission Co. on Nov. 30:

- A new 120-kV substation and 2 miles of double circuit 120-kV lines to handle an added 6 to 10 MVA in northern Michigan;
- A new 120-kV substation and 0.1 miles of underground cable to serve 5 MW of new DTE Energy load in Detroit; and
- A new 138-kV substation to serve 35 MW of new Consumers Energy load near Grand Rapids, Mich.

Bob McKee (left) and Jeff Webb | *© RTO Insider*

MISO said it is performing an independent reliability analysis "to determine that the projects [do] not cause any harm to the system." The RTO plans to schedule a Technical Studies Task Force meeting in January to discuss results, said Senior Manager of Transmission Expansion Planning Thompson Adu.

After 7 Years, Game Over for MISO's 'PAC Man'

After seven years in the PAC chair, American Transmission Co.'s Bob McKee has announced he will not seek re-election.

MISO PAC Liaison Jeff Webb called him the "PAC Man" and presented him with a Pac-Man themed blanket. "It is in fact, sadly, game over," Webb joked.

During his tenure, McKee oversaw MTEPs from 2010 to 2016. In parting words, he encouraged stakeholders to "take stock" and be actively involved in MISO's planning process.

ITC's Cynthia Crane will take over next year as chair.

— Amanda Durish Cook

MISO NEWS

Planning Subcommittee Briefs

MISO Says Common Assumption Set with PJM a No-Go

CARMEL, Ind. — MISO and PJM are not optimistic that they can use common assumptions in their interregional transmission planning.

MISO engineer Adam Solomon told the Planning Subcommittee Dec. 13 that while it is possible to make joint powerflow and economic models, they would not be based on a set of common assumptions. "We think we can make assumptions from both MISO and PJM using separate sensitivities," Solomon said during a Dec. 13 Planning Subcommittee meeting.

In an April 21 order, FERC directed MISO and PJM to explore with stakeholders the possibility of a joint model that uses identical model assumptions and criteria for regional transmission planning processes (EL13-88).

MISO has maintained that a joint model would be difficult to accomplish, as it studies two, five and 10 years into the future, while PJM studies five, seven and eight years ahead. In addition, MISO uses local balancing areas for dispatch, while PJM uses a single balancing area. PJM also does not forecast generation retirements, while MISO includes forecasted generation retirements in its futures modeling.

The RTOs' Oct. 25 informational filing to FERC detailed their reasoning as to why a single set of assumptions was infeasible. The RTOs told FERC that "most stakeholders agree with the RTOs' position that requiring the RTOs to adopt the same assumptions and criteria when conducting regional transmission planning would create significant challenges, including substantial revisions to each RTO's robust regional planning processes and cost allocation methodologies."

But Northern Indiana Public Service Co., whose complaint prompted the FERC order, said in comments to MISO that the two RTOs need a joint model because their different study processes lead to projects being categorized inconsistently (e.g., reliability, public policy or economic). "However, tests of NERC reliability thermal or voltage violations have less disparity between RTOs. Reliability models typically have similar topology, base resource modeling and demand assumptions," the utility said.

In a Nov. 15 filing with FERC, NIPSCO accused the RTOs' of ignoring the commission's directives. "The pattern of behavior shown by the RTOs … demonstrates that [they] are committed to interpreting the April 21 order as empowering the RTOs to eliminate the Coordinated System Plan Study for interregional planning, which is plainly contrary to the spirit, if not the letter, of the commission's orders," NIPSCO said.

At the Dec. 14 Planning Advisory Committee meeting, Adam McKinnie, chief utility economist for the Missouri Public Service Commission, asked MISO to create a common interregional model before it embarks on more studies, such as the MISO-SPP joint study running through the first quarter of 2017. (See *MISO-SPP Study Scope Finalized; Stakeholders Doubtful Projects will Result*.)

Ameren said MISO and PJM should use the same base models for system load conditions, such as light load, summer shoulder peak, winter peak and summer peak conditions. Other members, including Great River Energy, ITC Holdings, WPPI Energy and American Transmission Co. said they understood MISO's reluctance to adopt identical assumptions.

Retirement Risk, Deliverability Measured for MTEP 17

MISO's deliverability analysis for the 2017 Transmission Expansion Plan will identify transmission constraints and possible violations on a five- and 10-year horizon, MISO engineer Carlos Bandak said.

Bandak said the deliverability analysis will determine whether groups of generators in an area can operate at maximum capability without being "bottled-up." The information is used in granting or denying network resource interconnection service (NRIS).

After stakeholders expressed concerns that MISO would use historical limits for the deliverability analysis, Bandak reassured stakeholders that the RTO each year produces fresh results and does not test values from previous years, although it will not test above already-granted NRIS levels for existing generators.

Stakeholders argued that MISO might test above the approved NRIS level to a generator's potential capability.

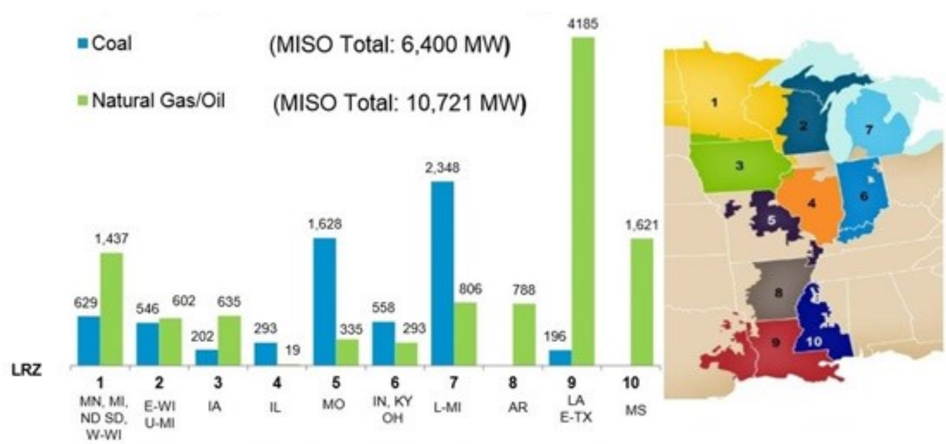
"We're not going to use the deliverability study to grant incremental capability. That would be too complicated," said MISO Director of Planning Jeff Webb, adding that the generator interconnection queue is the arena where owners should go if they want to be granted more generating capability.

"All we're doing here is making sure that generators continue to be deliverable through their interconnection service. There's nothing really new or strange here," Webb said.

MISO also will incorporate a retirement sensitivity analysis in MTEP 17's annual reliability assessment.

MISO will perform 10-year-out sensitivity

Continued on page 16



Projected age-related unit retirements by 2026 in MTEP 17 futures. (All retirements in this table are purely speculative and based on age assumptions in MTEP17 futures. | *MISO*

MISO News

FERC Orders Hearing in Entergy Formula Rate Dispute

FERC on Thursday ordered hearing and settlement procedures in a dispute between Entergy and its customers over the company's accounting for income taxes and post-retirement benefits in its formula rates tariff (ER16-1528).

The commission said the dispute raised unresolved factual issues and that Entergy's proposed formula rate changes may be unjust and unreasonable. It made the changes effective June 2015 and June 2016 but suspended them pending the settlement proceedings. The order consolidated two dockets, ER15-1436 and ER15-1453, with ER16-1528.

The multiple dockets stem from February 2013, when Entergy first filed proposed transmission formula rate templates to recover its transmission revenue requirements as a MISO member. The proposed rates were modeled on MISO's Tariff but incorporated practices established under Entergy's previous tariff for its operating companies.

In July 2015, Entergy reached a partial settlement on the formula rate templates with several customers, including the South Mississippi Electric Power Association and Arkansas Electric Cooperative Corp. By then, however, Entergy had already proposed two changes to the rate templates related to income taxes and retirement costs that were not reflected in the settlement.

The customers protested, contending that the changes did not reflect established practices under the Entergy tariff and were unsupported by its "grossly deficient" filing. They said Entergy's claim for recovery of $612.7 million in prepaid pension costs was unjustified and could increase its transmission revenue requirement by $8 million annually.

Entergy said the pension costs would increase rates by only $1.3 million per year.

— Tom Kleckner

Planning Subcommittee Briefs

Continued from page 15

analyses for age-based retirements modeled in MTEP 17's "existing fleet" future. By 2027, all coal units 65 years or older and all gas and oil units 55 years or older will be assumed to have been retired.

In 10 years, the MISO footprint will contain 6.4 GW of at-risk coal generation and 10.7 GW of susceptible natural gas and oil generation. The RTO places the current average age of its coal fleet at 38 years and its natural gas and oil fleet at 22 years.

MISO engineer Anton Salib said the RTO would build models until March and test them through May, with preliminary findings released in June. A full report is expected by September.

Ginger Hodge of Customized Energy Solutions asked if results would be included in the MTEP 17 Market Congestion Planning Study. Salib said the findings may inform the study, but information from a variety of analyses would also be used.

By the end of 2016, MISO expects $2 billion more of MTEP 15's transmission projects to be in-service. Project candidates for MTEP 17 are to be submitted by Sept. 15, 2017. Solomon said the overall scope of MTEP 17 studies will be completed by the end of this month.

In response to stakeholder feedback on the MTEP 17 scope, MISO told the Dec. 14's Planning Advisory Committee it would consider removing independent load forecasting from the MTEP process because it is not governed by the RTO's business practices. Purdue University's State Utility Forecasting Group currently estimates MISO's power demand. The PAC could weigh in on the future of the forecasting after the new year.

— Amanda Durish Cook

PJM News

Operating Committee Briefs

With 'Typical' Weather Expected, PJM Sees No Issues for CP's First Winter

VALLEY FORGE, Pa. — PJM is expecting "typical" temperatures and almost 50,000 MW of capacity beyond its projected peak load for the first winter using Capacity Performance, PJM's Chris Pilong told the Operating Committee last week.

While recent winters were impacted by anomalies such as El Nino, weather this season is likely to be about "average," he said. PJM's installed capacity for the winter is 183,665 MW, with 177,525 MW committed through the Reliability Pricing Model. The forecasted peak load is 135,548 MW.

"Average temperatures aren't going to be what's driving us as far as peak-load days," he said. "It's going to be the outliers."

Natural gas-fired capacity has increased by 17,225 MW since the polar vortex nearly three years ago to 61,513 MW, he said, about 35% of committed capacity. Of that, about half — 31,946 MW — is committed through CP.

An Operations Assessment Task Force assessment of pipeline-disruption sensitivity found no reliability issues for base and N-1 analyses, Pilong said. "The good news was even under the worst-case scenario, everything was solid," he said.

By the end of the year, an additional 2,800 MW of generation will have been brought online since this summer, he said. The system also will have the benefit of transmission upgrades on the Baltimore Gas and Electric, Dominion, Commonwealth Edison and American Electric Power systems.

PJM Moves to Cut Operator-Training Grace Period in Half

The grace period for dispatchers at utilities' market operations centers and small generation plants to complete initial training will be reduced from 12 months to six months in revisions PJM is proposing for Manual 40.

"Our long-range plan is to get that number [of untrained dispatchers] to zero," PJM's Glenn Boyle said. "What we're saying is that's too much exposure risk."

He said PJM is hoping to have the grace period removed entirely by next year.

Regulation Requirement Changing from 'Peak' to 'Ramp'

PJM is proposing to change the way it sets regulation requirements, replacing the targets for on- and off-peak periods with those for on- and off-ramp intervals to better capture seasonal system conditions.

The revisions, which will be incorporated in Manuals 11 and 12, were recommended by the Regulation Market Issues Senior Task Force.

The lower regulation requirement of 525 effective MW, which currently applies during off-peak hours of midnight to 04:59, would apply during off-ramp hours. The requirement for the on-peak hours of 05:00 to 23:59 would be applied to the on-ramp and increase from 700 to 800 effective MW.

On- and off-ramp periods will vary by season. From Sept. 1 through Nov. 30, for example, the on-ramp period will be hours ending 6:00 through 8:00 and 18:00 through 24:00. For the winter, the morning ramp starts one hour earlier and ends one hour later while the evening ramp begins an hour earlier.

The seasonal periods will be posted on the RTO's website. PJM's Eric Hsia said he plans to also announce them at the Operating Committee meetings starting two months prior to the beginning of the affected season.

Season	Morning On Ramp (hours ending)	Evening On Ramp (hours ending)
Fall: September 1 – November 30	6:00–8:00	18:00-24:00
Winter: December 1 – February 29	5:00-9:00	17:00-24:00
Spring: March 1 – May 31	6:00–8:00	18:00-24:00
Summer: June 1 – August 31	6:00–14:00	19:00-24:00

Proposed regulation requirements. On ramp: 800 MW, off ramp: 525 MW | *PJM*

PJM Won't Pay for Frequency Response Under FERC NOPR

FERC's Nov. 17 rulemaking that would require most new generators to have primary frequency response capability left it to individual RTOs to decide if compensation is warranted for the service, and PJM currently believes it's not, Hsia said.

The rule would apply to both synchronous and nonsynchronous facilities as a condition of interconnection. Nuclear units are exempt.

Hsia said he didn't agree with the argument that generators should be compensated for lost-opportunity costs, noting that the Notice of Proposed Rulemaking would not require them to preserve "headroom" for the frequency response when offering their output for sale (RM16-6). (See *FERC: Renewables Must Provide Frequency Response*.)

He acknowledged "ongoing conversation" on the topic, however. Comments on the NOPR are due to FERC on Jan. 24.

Members Question Redundancy of Pseudo-Tie Efforts

Members asked PJM staff why the RTO is seeking to create a *pro forma* pseudo-tie agreement when the issue of pseudo-ties is already being discussed by the Underperformance Risk Management Senior Task Force.

"The lack of this agreement has resulted in a lack of uniformity," PJM's Jacqui Hugee said.

Staff wanted to develop such a document for the task force but couldn't complete it fast enough to avoid delaying the task force's progress, she said. The effort to develop a *pro forma* document is being done in coordination with the task force, she said, and PJM doesn't plan to make multiple filings on the topic with FERC. (See related story, *MISO Stakeholders Narrowly Support New Pseudo-Tie Rules*, p.13.)

— Rory D. Sweeney

PJM NEWS

Market Implementation Committee Briefs

Protocol Changes Proposed for Implementing Order 825

VALLEY FORGE, Pa. — PJM is preparing several proposed rule changes in response to FERC Order 825, which requires RTOs to align their settlement and dispatch intervals and implement shortage pricing.

PJM's Ray Fernandez walked the Market Implementation Committee through planned Operating Agreement and Tariff revisions that would be part of a compliance filing planned for Jan. 11. The changes would calculate balancing operating reserve deviations in five-minute intervals but aggregate charges and credits daily for allocations. (See "More Adjustments for Five-Minute Settlement," *PJM Market Implementation Committee Briefs*.)

Fernandez's presentation included an example in which a unit with no net deviations during a day would have incurred balancing charges under the current process but wouldn't under the proposed one.

"With the proposal that PJM has, we wouldn't be breaking down [imbalances] to the bus level," he said. "It minimizes the pot of dollars that we're charging."

Stakeholders, however, voiced skepticism on multiple points. Brock Ondayko of American Electric Power expressed concern that units might not be able to follow generation signals so precisely and risk incurring additional penalties.

Generators are "basically chemical factories whose byproduct is energy" and "don't necessarily follow things perfectly," he said. "We're never right on. … I'm concerned that the quantity of operator imbalance could be increased significantly."

Other members questioned who would lose out on the changes, noting that reduced charges for one unit implies reduced credits for someone else.

"Whether it's a positive impact on balancing congestion or a negative one is unclear," Direct Energy's Jeff Whitehead concluded. "I'm trying to understand the tradeoffs."

In a separate presentation, PJM's Lisa Morelli unveiled proposed revisions to the operating reserve demand curve, which PJM believes are necessary to appropriately implement Order 825's five-minute interval requirement. PJM hopes to submit the revisions as a Section 205 filing around March 1.

The revisions would add an additional step in the curve at the $300 penalty factor that would allow the reserves to be "extended," or increased. Currently, reserve requirements can only be extended in specific situations related to the issuance of hot or cold weather alerts.

PJM increased the day-ahead scheduling reserve requirement for 901 hours between January 2015 and September 2016, almost 6% of total hours. On average, PJM increased the requirement by 5,000 MW.

While Order 825 specified a May 11, 2017, implementation date, PJM plans to request implementation of its proposals on five-minute settlements and shortage pricing simultaneously on Feb. 1, 2018. It would seek a response by Feb. 15.

If FERC approves the delayed implementation date, PJM would relax its timeline for the 205 filing until April. Otherwise, it will keep its March 1 target for the 205 filing and request shortage pricing be implemented simultaneously with five-minute settlements.

	Current		Proposed	
	Penalty Factor	MW	Penalty Factor	MW
Step 1	$850	Economic Maximum of the single largest contingency	$850 (no change)	Actual output of the single largest contingency (changes dynamically in real-time)
Step 2 (Permanent)	N/A	N/A	$300	Step 1 MW + 190 MW
Step 3 (Extended)	$300	Step 1 MW + Additional Reserve MW	$300 (no change)	Step 2 MW + Additional Reserve MW

PJM's proposed changes to the operating reserve demand curve | *PJM*

Rules on Fuel-Cost Policy Revocations Continue to Hang Up Approval

Stakeholders are nearing agreement on fuel-cost policy revisions but remain concerned about proposed protocols for revoking policies. (See "Fuel-Cost Policy Revisions Face Another Hurdle," *PJM Markets and Reliability and Members Committees Briefs*.)

Despite assurances from PJM that the revocations are very unlikely to be used and are meant as a last resort in the event of fraud or some other egregious problem, members were not satisfied.

"I think we've spent more time talking about this than we will ever spend using it," PJM's Steve Shparber said. "This is not expected to occur likely ever."

"From a culture standpoint, it strikes me as something we should not be doing to write things up that we think will never occur," countered American Municipal Power's Ed Tatum. "I just think it's inappropriate. It's impossible. And if we're going to do it, let's do a good job of it. … What we're talking about right now is some language that is unclear as to how it's going to work."

He and other stakeholders argued that PJM hadn't clearly defined parameters for issuing a revocation. Bob O'Connell of PPGI Fund A/B Development expressed concern that PJM appeared to be implying it would be making judgments about whether operators were committing fraud.

Joe Bowring, PJM's Independent Market Monitor, questioned the RTO's insistence on getting the fuel-cost policy revisions approved prior to any requirement from FERC.

"Why wordsmith it now when there's no order?" he asked.

Bowring also said his office is "remaining agnostic" on variable operations and maintenance costs and "not focusing on VOM primarily at the moment." He later clarified that he was talking about whether it should be included in fuel-cost policies, not whether he planned to investigate them

Continued on page 19

PJM NEWS

PC/TEAC Briefs

Members Request Additional Clarity on Recommended Tie-Line Timeline

VALLEY FORGE, Pa. — PJM's proposed timeline for reviewing tie-line requests will need another round of revisions before members are comfortable with endorsing it.

Two clarifications precluded members from bringing it to an endorsement vote at last week's Planning Committee meeting. The first concern was an implication that the applicant must present their request at a meeting of the System Operations Subcommittee's transmission owners group (SOS-T) following PJM's legal and technical review. The second issue was the timeline's awkward construction, in which it counts down to a FERC filing date and then counts down again to an in-service date.

"We thought it was valuable, but if it's causing issues, we can remove it," PJM's Sue Glatz said. She went on to request an endorsement vote with the understanding that the clarifications will be made.

Stakeholders questioned PJM's pressure to secure approval despite reservations.

"It's essential that these documents be clear and concise. I'm not wishing this on anyone, but there is the possibility that some of us might not be around to interpret them," American Municipal Power's Ed Tatum said.

PJM's Paul McGlynn countered that the process has been going on for quite some time. "We've been at it for four months now," he said.

Project-Selection Guidelines Criticized as Too Subjective

PJM unveiled guidelines for how it will select market efficiency projects, noting a "bright line" criterion that it must relieve at

Continued on page 20

Market Implementation Committee Briefs

Continued from page 18

as part of validating cost-based offers.

No Solution Yet for Energy Offer Validation

PJM is still considering how it will comply with FERC's requirements in Order 831 to verify incremental energy offers above $1,000/MWh. (See *New FERC Rule Will Double RTO Offer Caps*.)

"We haven't done a lot of work on validating" offers, PJM's Adam Keech said. A multi-phased approach may be adopted, depending on the result of the fuel-cost policy proposal, he said.

The rule's effective date is Feb. 21, but PJM's compliance filing isn't due until May 8, so the RTO intends to implement its final plan immediately following the compliance filing.

Bowring suggested asking FERC to clarify its wishes on the topic. The current plan "doesn't seem like a great process," he said.

Credit Limit Changes Pass Despite Exelon Objections

Exelon's Sharon Midgley spoke passionately in opposition to PJM's proposed alternative to the current credit requirements for participation in financial transmissions rights auctions, but she found no other vocal support.

Under current rules, FTR credit requirements are calculated in two parts: one based on price and the adjusted historical values of individual FTRs, and the second a portfolio-based "undiversified credit adder" applied to net counterflow portfolios.

Some FTR holders sought an alternative, saying the undiversified adder caused clearing delays and credit uncertainty.

The alternative, previously approved by the Credit Subcommittee, eliminates the portfolio adder in exchange for increasing the historical adjustment factor in underlying credit calculations for historically counterflow paths from 10% to 25%.

"We do think they increase our credit requirements," Midgley said. No one shared her concern, however, and the proposal was endorsed 88-34 with 15 abstentions.

PJM, IMM Partner on Capacity-Replacement Revision

In a swift response to rule changes they felt weakened market safeguards, PJM and the Monitor presented a jointly developed proposal to again revise Manual 18.

At November's Markets and Reliability Committee meeting, members ignored objections from both PJM and the Monitor and approved Manual 18 revisions that allowed for immediate replacement of capacity obligations. PJM had offered an amendment to the proposal that would have addressed its concerns, but it never came to a vote, as the original proposal was endorsed. (See "Citigroup Wins Change on Capacity Resales," *PJM Markets and Reliability and Members Committees Briefs*.)

The Monitor filed a complaint with FERC in response and joined PJM in proposing the newest revision, which is similar to their original amendment. At least some stakeholders were receptive.

"The IMM has convinced Calpine that we do need to put something in place," said David "Scarp" Scarpignato in noting his company's support of the new proposal.

Bowring said it was "not as strong as the optimal rules" and suggested returning to the previous protocols if the current proposal wasn't satisfactory, but stakeholders said the proposal broached issues that needed to be addressed.

Operating Parameters, ARR Enhancements Endorsed

Members endorsed by acclimation and with little discussion new definitions for operating parameters and rule changes regarding residual auction revenue rights.

The updated definitions for "soak time" and "minimum run time" affect several manuals and governing documents. (See "Monitor Concerns Delay Operating Parameter Revisions," *PJM Market Implementation Committee Briefs*.)

The changes on residual ARRs, proposed by Exelon and Direct Energy, will require PJM to run another simultaneous feasibility test proration with all negatively valued bids removed. (See "Stakeholders Debate ARR Changes," *PJM Market Implementation Committee Briefs*.)

— Rory D. Sweeney

PJM NEWS

PC/TEAC Briefs

Continued from page 19

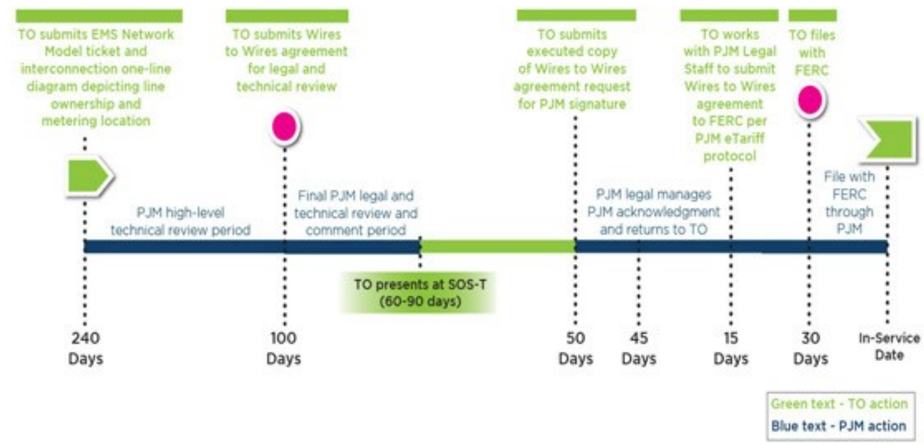
least one economic (capacity or energy) constraint. Projects also must clear a benefit/cost ratio of 1.25:1 and proposals with estimated costs of more than $50 million will be subject to an independent review.

John Farber of the Delaware Public Service Commission questioned what he called PJM's "market efficiency at any cost" metrics and asked that it increase its focus on gathering "objective data to move this from a subjective to an objective process" going forward. He said PJM's analysis is subjective and that cost containment caps are not a "panacea."

PJM's Asanga Perera said congestion created by any outages needed to complete a proposed project would be factored into decisions if it's useful, but that it's "tough" to include short-term factors and a "one-time thing" like an outage into a 15-year analysis.

"I think what we're suggesting with some of these slides is that a project without outage congestion might be a better choice," McGlynn said.

PJM will publish the guidelines, which will be effective for the 2016/17 transmission planning cycle, on the market efficiency web page.



Recommended tie-line process actions | *PJM*

New Forecast Sees Further Load-Growth Reductions

PJM is again reducing its load growth projections due to the economic outlook and increased efficiency.

In its preliminary 2017 forecast, expected summer load for 2020 dropped 2.1% compared to last year's forecast, while that for 2022 was down 2.9%. The winter 2020/21 forecast dropped 2.6% and 2022/23 was down 3.5%. 2020 was chosen for comparison because it's the next year for the Base Residual Auction; 2022 is the year used in the Regional Transmission Expansion Plan study.

Analysis Needed to Answer Winter Resource Adequacy PS

PJM's Tom Falin said the first step to addressing a problem statement approved last month on winter resource adequacy and capacity requirements will be to ensure PJM's winter model is accurate. (See PJM Stakeholders Reject CP Rule Changes, OK Additional Study.)

Work is being done to assess how well it processes all factors, including how to quantify the operational risks of activities such as transmission outages and generator maintenance.

"Our suggestion is going to be that PJM take the next two or three months to assess internally," he said.

He expected to have more information for March's Planning Committee meeting.

'Immediate Need' Designations Questioned

At the meeting of the Transmission Expansion Advisory Committee, stakeholders questioned PJM's determination of "immediate need" for several transmission reliability projects and criticized the decision not to open them to competitive bidding.

In particular, an American Electric Power project in northeastern Indiana raised eyebrows. The company says an outage of its South Butler-Collingwood 345-kV line would result in the loss of more 300 MW of load.

One fix, estimated at $76.5 million, would involve a new 345-kV switching station and a new double-circuit 345-KV line of 17 miles. PJM said it favors an alternative proposal from AEP estimated at $107.7 million because it would also address aging-infrastructure concerns.

PJM's recommendation rankled some members, who felt the project could have been identified earlier to allow for competitive bidding. Some also questioned including costs for local infrastructure that they said shouldn't be allocated throughout the RTO.

Five transmission towers along the route are in immediate need of replacement, 79 will need to be addressed within three years and another 22 will need to be fixed soon thereafter, according to AEP's assessment.

Sharon Segner of LS Power questioned PJM's findings on two projects it plans to award to Dominion, the incumbent transmission owner, based on immediate need. According to Dominion's proposal, the projects aren't slated to be completed until 2021, which is beyond PJM's definition for an "immediate need" project, Segner said. She suggested opening a 30-day window for competitive transmission developers like her company to propose alternatives.

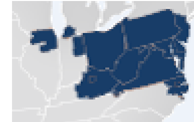
"Right now, the incumbent transmission owner cannot meet it in three years. Therefore, it would seem to me the right thing to do would be to see if anyone can meet it in the proposal window," she said.

PJM's Steve Herling said that would create months of analysis and third-party verification for PJM that would only delay AEP from completing the project.

"We've already considered all of these factors, and what we have here is our decision. If you take exception to our decision, you can communicate it to the board," he said.

PJM staff also pointed out that a recent

Continued on page 21



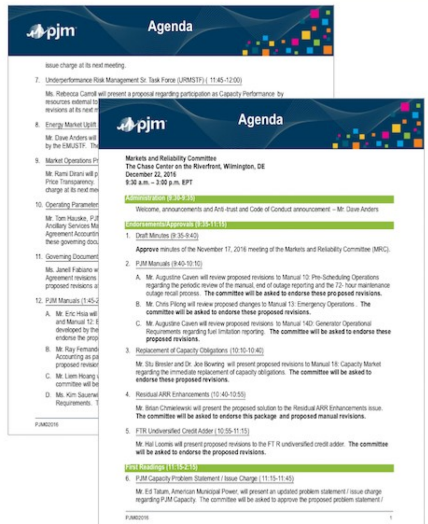
PJM NEWS

MRC/MC Preview

Below is a summary of the issues scheduled to be brought to a vote at the Markets and Reliability Committee on 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.

NOTE: There is no Members Committee meeting this month.


pjm Agenda

Markets and Reliability Committee
The Chase Center on the Riverfront, Wilmington, DE
December 22, 2016
9:30 a.m. – 3:00 p.m. EPT

Administration (9:30-9:35)

Welcome, announcements and Anti-trust and Code of Conduct announcement – Mr. Dave Anders

Endorsements/Approvals (9:35-11:15)

1. Draft Minutes (9:35-9:40)

Approve minutes of the November 17, 2016 meeting of the Markets and Reliability Committee (MRC).

2. PJM Manuals (9:40-10:10)

A. Mr. Augustine Caven will review proposed revisions to Manual 10: Pre-Scheduling Operations regarding the periodic review of the manual, end of outage reporting and the 72- hour maintenance outage recall process. **The committee will be asked to endorse these proposed revisions.**

B. Mr. Chris Pilong will review proposed changes to Manual 13: Emergency Operations.. **The committee will be asked to endorse these proposed revisions.**

C. Mr. Augustine Caven will review proposed revisions to Manual 14D: Generator Operational Requirements regarding fuel limitation reporting. **The committee will be asked to endorse these proposed revisions.**

3. Replacement of Capacity Obligations (10:10-10:40)

Mr. Stu Bresler and Dr. Joe Bowring will present proposed revisions to Manual 18: Capacity Market regarding the immediate replacement of capacity obligations. **The committee will be asked to endorse these proposed revisions.**

4. Residual ARR Enhancements (10:40-10:55)

Mr. Brian Chmielewski will present the proposed solution to the Residual ARR Enhancements issue. **The committee will be asked to endorse this package and proposed manual revisions.**

5. FTR Undiversified Credit Adder (10:55-11:15)

Mr. Hal Loomis will present proposed revisions to the FT R undiversified credit adder. **The committee will be asked to endorse the proposed revisions.**

First Readings (11:15-2:15)

6. PJM Capacity Problem Statement / Issue Charge (11:15-11:45)

Mr. Ed Tatum, American Municipal Power, will present an updated problem statement / issue charge regarding PJM Capacity. The committee will be asked to approve the proposed problem statement /

PJM©2016 1

2. PJM Manuals (9:40-10:10)

Members will be asked to endorse the following proposed manual changes:

- Manual 10: Pre-Scheduling Operations. Revisions reflect periodic review and clarify rules around maintenance outage recalls.
- Manual 13: Emergency Operations. Revisions reflect periodic review.
- Manual 14D: Generator Operational Requirements. Revisions address fuel-limitation reporting.

3. Replacement of Capacity Obligations (10:10-10:40)

Members will be asked to endorse revisions to Manual 18: Capacity Market regarding the immediate replacement of capacity obligations. (See "Citigroup Wins Change on Capacity Resales," *PJM Markets and Reliability and Members Committees Briefs* and "PJM, IMM Partner on Capacity-Replacement Revision" in this edition's *PJM Market Implementation Committee Briefs*, p.18.)

4. Residual ARR Enhancements (10:40-10:55)

Members will be asked to endorse a rule change concerning residual auction revenue rights that was approved last week by the Market Implementation Committee. The changes, proposed by Exelon and Direct Energy, will require PJM to run another simultaneous feasibility test and *pro rata* distribution with all negatively valued bids removed. (See "Stakeholders Debate ARR Changes," *PJM Market Implementation Committee Briefs*.)

5. FTR Undiversified Credit Adder (10:55-11:15)

Members will be asked to approve proposed revisions to the undiversified credit requirements for participation in financial transmissions rights auctions that were approved last week by the Market Implementation Committee. Under current rules, FTR credit requirements are calculated in two parts, one based on price and the adjusted historical values of individual FTRs, the second a portfolio-based "undiversified credit adder" applied to net counterflow portfolios — a process that some said caused clearing delays and credit uncertainty. The new rules eliminate the undiversified portfolio adder in exchange for increasing the adjustment factor in underlying credit calculations for historically counterflow paths from 10% to 25%.

5. Market Implementation Committee Charter (10:25-10:30)

Members will be asked to approve the updated MIC Charter, which eliminates references to "working groups." (See "'Working Groups' Removed from MIC Charter," *PJM Market Implementation Committee Briefs*.)

— Rory D. Sweeney

PC/TEAC Briefs

Continued from page 20

FERC docket offered stakeholders the opportunity to raise these concerns. The commission's July order in that case made clear that the definition is based on the date of need, not the in-service date (ER16-736, EL16-96). (See *FERC Rejects PJM Cost Allocation on Dominion Project*.)

PJM Review of Artificial Island Bid Elements Completed

Installing optical ground wire (OPGW) and new relays won't resolve reliability issues at Artificial Island as originally expected, PJM's analysis has found. (See *PJM Board Halts Artificial Island Project, Orders Staff Analysis*.)

"There may be benefits to installing the optical ground wire and new relay, but that scope of work would not directly address the operational performance issue," McGlynn explained.

An OPGW serves as both a ground and a telecommunications link. PJM determined that although high-speed relaying using such wires would improve the clearing times for line faults, some bus-fault clearing times were more limiting. "Since the timing is not improved by the OPGW and line relay changes, they will not improve the stability margin," PJM said.

One of the preliminary recommendations from PJM's analysis is to remove the ground wire and relay upgrades from the project scope, McGlynn said.

Stakeholders asked whether, based on the scope changes, PJM plans to re-evaluate submitted proposals, but Herling said that was not possible.

"Realistically, we're only looking at the finalists … in the context that things have changed. … We're not going to go back to the most expensive projects that were eliminated," he said. "We're still working our way through the cost issues and the constructability issues. … Obviously, we still have a lot of work to do."

— Rory D. Sweeney

SPP NEWS

SPP-MISO IPSAC Turns Attention to 2017 Study

SPP and MISO continue to study seven potential joint transmission projects across their seam, but much of their focus is now turning to developing the 2017 joint study by next April.

Staff from the two RTOs told their Interregional Planning Stakeholder Advisory Committee on Friday that they have already begun to put together a work plan that includes a study scope, timeline and Tariff and joint operating agreement changes needed to accommodate the study.

RTO staffers met in October at MISO's Louisiana offices to lay out a high-level framework for the study, which would end in 2019. Staff hope to improve coordination of their regional processes and sharing of regional planning assumptions.

"As we develop our regional plans individually, we would start developing regional candidate projects," said MISO's Davey Lopez, advisor of planning coordination and strategy. "Both parties agreed we want to plan for the best value, which may not be the cheapest solution."

Lopez and his counterpart, SPP Interregional Coordinator Adam Bell, said their boards would be able to evaluate the regional projects and interregional projects on the same timeline, eliminating one of the stakeholder complaints in recent years.

"One of major hurdles we have is the timing of the regional processes," Bell said. "Both sets of stakeholders will be able to look at regional and interregional plans at the same time, and pick the best project. One is not winning out by virtue of finishing first."

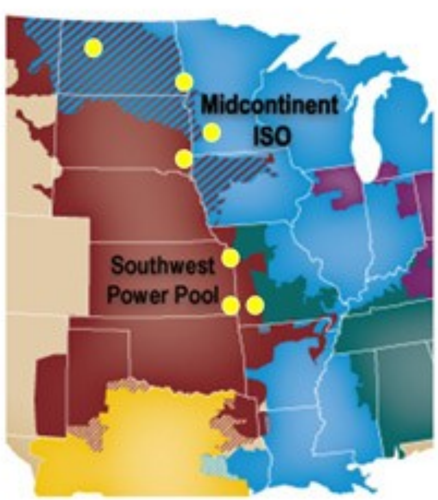
Lopez told the IPSAC that the 2017 study will begin as the 2016 coordinated study process ends, using the latter's study results as an input. "We'd like to ramp it up in April 2017, hit the ground running and jump right into another study," he said.

The 2016 analysis has resulted in seven potential projects, primarily in the Dakotas and along the Kansas-Missouri border. Lopez said the list may be reduced further but that it is "good information for the 2017 study."

Three of the projects would solve market-to-market flowgates, which have resulted in payments from MISO to SPP totaling $2.75 million.

Nine entities have submitted 32 solution ideas to address the project needs posted in October. Several of the solutions were duplicates of, or similar to, others.

Final study results will be shared with the IPSAC during its next meeting, tentatively scheduled for February.



NEED ID	CONSTRAINT
1	Rugby WAUE-Rugby OTP Tie FLO Rugby – Balta 230 kV
2	Hankinson - Wahpeton 230kV FLO Jamestown - Buffalo 345kV
3	Sub3 - Granite Falls 115kV Ckt1 FLO Lyon Co. 345/115 kV transformer
4	Sioux Falls - Lawrence 115kV FLO Sioux Falls - Split Rock 230kV
5	Northeast - Charlotte 161kV FLO Northeast - Grand Ave West 161kV
6	Neosho - Riverton 161kV FLO Neosho - Blackberry 345kV
7	Brookline 345/161kV Ckt 1 Transformer FLO Brookline 345/161kV Ckt 2 Transformer

MISO-SPP potential joint projects. IDs run from top to bottom (with 6 and 7 left to right) | *SPP-MISO IPSAC*

Competitive Tx Process Task Force Suggests Criteria Change

The Competitive Transmission Process Task Force completed its review of the documents to be used by transmission developers bidding on projects through SPP's Order 1000 competitive process.

Stakeholders determined that the inflation rate (2.5%), discount rate (8%) and operations and maintenance escalation rates should be prescribed by SPP in its solicitation.

Duke Energy's Bob Burner proposed the group use a "pass-fail" grading system rather than point-scoring for certain qualitative items evaluated by the industry expert panel (IEP).

Staff noted the Tariff language gives the IEP sole discretion in determining how it scores competitive proposals but agreed to recommend to the panel which items should fall into the pass-fail category. Staff will draft a revision request that would remove certain pass-fail items from the solicitation process. Points allotted to the scoring categories would not be impacted.

The task force will meet again Jan. 9, in preparation for the Markets and Operations Policy Committee meeting two weeks later.

Gas-Electric Coordination Report Filed with FERC

SPP on Friday filed with FERC its first informational report on the RTO's efforts to coordinate gas and electric scheduling practices. Staff shared a draft of the report two weeks ago with the Gas-Electric Coordination Task Force. (See "SPP to Deliver Positive Report to FERC on Gas-Scheduling Practices," *SPP Briefs*.)

The report was filed to comply with FERC Order 809, which required RTOs to improve the alignment of their market schedules with those of interstate gas pipelines (RM14-2). SPP's changes took effect Sept. 30.

SPP Sets New Winter Peak Mark

SPP set a new winter demand peak earlier this month, hitting 37,780 MW at 7:21 a.m. Dec. 9. The mark broke the previous record of 37,412 MW set Jan. 18.

— Tom Kleckner

FERC NEWS

FERC Proposes Changes to Interconnection Rules

By Michael Brooks

FERC on Thursday proposed several revisions to its *pro forma* large generator interconnection rules intended to increase certainty and transparency for new resources (RM17-8).

The commission issued the Notice of Proposed Rulemaking in response to feedback gathered at a May technical conference and in subsequent comments. (See *Generators, Tx Operators Spar over Interconnection Processes Before FERC*.) Generation developers have long complained about the long wait time for interconnection approvals. Transmission providers complained about the number of projects that drop out of the interconnection queue — increasing the number of restudies needed — and the high concentration of projects, such as wind farms, in small geographic areas.

"Cost and timing uncertainty presents a significant obstacle, as some interconnection customers are less able to absorb unexpected and potentially higher costs or extended timelines resulting from the withdrawal of requests higher in the queue," the commission said in a news release. "A lengthy interconnection process can be a challenge to generation technologies that are evolving rapidly. The commission believes that interconnection processes should be capable of incorporating rapidly evolving generation technologies into an interconnection request while maintaining system reliability."

FERC detailed 14 changes to the *pro forma* Large Interconnection Agreement and Interconnection Procedures that it said should address these and other concerns. Among the most notable are requirements that transmission providers post the methodologies used to form network models in their interconnection studies, as well as congestion and constraint information, on their Open Access Same-Time Information System (OASIS) sites.

© RTO Insider

They would also be required to allow interconnection customers to:

- limit their requested level of service below their generating facility's capacity;
- operate on a limited basis before the full interconnection process is completed; and
- use surplus interconnection service at existing points.

RTOs and ISOs would also be required to develop a resolution process for interconnection disputes between developers and transmission owners.

The reforms would apply to projects over 20 MW, but the commission is seeking comment on whether any of them should apply to rules for small generators as well.

Commissioner Colette Honorable cited the need to accommodate new technologies, such as energy storage, as one of the main reasons for the NOPR. Two of FERC's changes dealt with energy storage resources specifically. One would change the definition of "generating facility" in the *pro forma* documents to explicitly include storage.

The other would require transmission providers to evaluate their methodologies for modeling storage resources in their interconnection studies and report their findings to FERC.

"The commission believes the proposed reforms will benefit interconnection customers through more timely and cost-effective interconnection and will benefit transmission providers by mitigating the potential for serial restudies associated with late-stage interconnection request withdrawals," it said.

"I think this is a good example of the kind of bread-and-butter work that FERC does that may not always receive much public attention: work that is technical and weedy, but work that nevertheless is very important," Chairman Norman Bay said at the commission's open meeting Thursday. "I think today's NOPR strikes an important balance between the needs of interconnection customers and those of transmission owners."

Stakeholders have long sought commission action on the interconnection process. The *pro forma* agreement and procedures were established in 2003 and most recently updated in 2008. May's tech conference was prompted by a petition from the American Wind Energy Association last year. (See *After Years of Questions, Interconnection Customers Await Answers*.)

Comments are due no later than 60 days after the NOPR's publication in the *Federal Register*.

"I think this is a good example of the kind of bread-and-butter work that FERC does that may not always receive much public attention..."

FERC Chairman Norman Bay

FERC NEWS

FERC: Let Fast-Start Resources Set Prices

By Rich Heidorn Jr.

RTOs and ISOs would be required to incorporate fast-start resources into energy and ancillary services pricing under a Notice of Proposed Rulemaking approved by FERC on Thursday (RM17-3).

The commission said new rules are required to allow fast-start resources to set LMPs — changes regulators said should reduce uplift and provide more accurate price signals to encourage investments.

"Without some form of fast-start pricing, most fast-start resources are not eligible to set prices even when they are the marginal resource," Daniel Kheloussi, a staffer in FERC's Office of Energy Policy and Innovation, said during a presentation at the commission's monthly meeting. "Further, even when fast-start resources can set prices, they may not be able to recover their commitment costs, such as start-up and no-load costs, through prices. As a result, prices may not reflect the marginal cost of serving load."

The commission said fast-start resources are unique because they are often dispatched to inflexible minimum or maximum operating limits, making them ineligible to set LMPs. They also are usually committed in real-time.

"As a result, the cost to commit these resources is incurred at roughly the same time the incremental energy costs are incurred, which raises the question of whether the commitment costs should be included in the LMP," the commission said. "Finally, fast-start resources can arguably respond quickly enough to be considered part of an RTO's/ISO's operating reserves even when they have not yet been committed."

Seeking to build on the RTOs' best practices, the NOPR would:

- Standardize the definition of fast-start resources to include any resource committed by the RTO/ISO that is able to start up within 10 minutes or less, has a minimum run time of one hour or less and that submits economic energy offers to the market. The definition would be technology-agnostic.
- Require that an RTO must incorporate the start-up and no-load costs (commitment costs) of a committed resource in energy and operating reserve prices for the resource's minimum run time.
- Require RTOs to relax the resource's economic minimum operating limit (eco min) when calculating prices — treating it as if it is dispatchable from zero to the economic maximum operating limit (eco max).
- Allow offline fast-start resources to set prices under certain system conditions when they are economic and feasible.
- Require RTOs to incorporate fast-start pricing in both the day-ahead and real-time markets to support price convergence between the two.

The NOPR is the third issued by the commission since it initiated a proceeding on price formation in RTO/ISO markets in June 2014 (AD14-14). It follows a June order requiring RTOs to align their settlement and dispatch intervals and implement shortage pricing during any shortage period (RM15-24). (See *FERC Issues 1st RTO Price Formation Reforms*.) In November, the commission doubled the "hard" offer cap for day-ahead and real-time markets to $2,000/MWh. (See *New FERC Rule Will Double RTO Offer Caps*.)

Inflexible

Fast-start resources are often required to be dispatched at their eco min or are block-loaded — in which the eco min equals its eco max.

Because the system may not need all of the resource's eco min to meet load, other resources must be dispatched down, making them the most economic option to serve the next increment of load. "Therefore, despite the fact that a fast-start resource is essentially marginal, this restriction prevents a fast-start resource dispatched at its economic minimum operating limit from setting the LMP," the commission said.

Thus, some RTOs have relaxed the resources' eco min limits, treating them as dispatchable in a pricing algorithm separate from the dispatch algorithm. But while these changes can improve price signals — especially during stressed conditions when the need for fast-start resources is the greatest — the disconnect between prices and dispatch instructions can cause over-generation. Only some RTOs conduct reconciliations between the pricing and dispatch runs to prevent excess generation, FERC said.

RTOs Have Differing Approaches

In comments filed following the commission's technical workshops on price formation, many stakeholders said they would support changes allowing resources dispatched at their operating limits to set LMP and allowing start-up and no-load costs to affect prices. The Electric Power Supply Association and Western Power Trading Forum said such changes could help address CAISO's "duck curve" by redistributing excess costs incurred during the middle of the day to the ramping periods.

The commenters noted that start-up time requirements for quick-start resources range from 10 minutes in NYISO, MISO and SPP, to 30 minutes in ISO-NE and two hours in PJM and CAISO.

Several stakeholders praised MISO's extended LMP. The program, implemented in March 2015, is designed to reduce uplift by incorporating all offer costs into market clearing prices. (See *MISO Study Undercuts IMM Proposal on Expanding ELMP Pricing*.) The RTO is planning to implement ELMP Phase II to apply fast-start pricing to more peaking resources.

NYISO and ISO-NE also received some praise, while Golden Spread Electric Cooperative criticized SPP, saying the RTO's market design and operator practices fail to reflect fast-start resources' costs and their value to the system.

NYISO worked with its Market Monitoring Unit and stakeholders on revising its "hybrid gas turbine pricing logic," resulting in a Dec. 14 FERC filing in which the ISO proposed broadening its eligibility criteria to allow all fast-start resources to be eligible to set prices in its real-time energy market (ER17-549).

ISO-NE will be implementing new rules effective March 1, 2017, to incorporate no-load and start-up costs in LMPs (ER15-2716).

Continued on page 26

FERC NEWS

FERC: Let Fast-Start Resources Set Prices

Region	Fast-Start Resource Definition	No-load costs incorporated in LMPs?	Startup costs incorporated in LMPs?	Set DA prices?	Set RT prices?	Offline prices set LMP?
FERC NOPR	**Start-up:** within 10 minutes or less. **Minimum run time:** one hour or less. **Other:** Submits economic energy offers.	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
CAISO	**Start-up:** online within two hours or less. **Other:** can be committed in CAISO's 15-minute market or short-term unit commitment process.	Yes	No	Yes	Yes	No
ISO-NE	**Start-up:** 30 minutes or less. **Minimum run time:** one hour or less. **Minimum down time:** one hour or less.	Yes (1)	Yes (1)	No	Yes	No
NYISO	Does not apply fast-start pricing to all fast-start resources.(2) (3)	N/A	Yes	Yes	Yes	Yes
PJM	**Start-up:** two hours or less (fast start CT). Block-loaded resource: eco min = eco max.	No	No	Yes (4)	Yes	No
MISO	**Start-up:** 10 minutes or less. **Minimum run time:** one hour or less.(6)	Yes	Yes	Yes	Yes	Yes (5)
SPP	**Start-up:** 10 minutes or less. **Minimum run time:** one hour or less. **Other:** total minimum down time one hour or less. (10)	No (7)	No (8)	Yes (9)	Yes	No

(1) New rules effective March 1, 2017 (ER15-2716).

(2) Uses "hybrid gas turbine pricing logic" and "offline gas turbine pricing logic" for all fast-start block loaded resources in its real-time energy market. Allows all fast-start block loaded resources to set price in its day ahead energy market.

(3) Worked with Market Monitoring Unit and stakeholders on revising its "hybrid gas turbine pricing logic." In a Dec. 14 FERC filing (ER17-549), the ISO proposed broadening its eligibility criteria to allow all fast-start resources to be eligible to set prices in its real-time energy market.

(4) Yes. But generally limited to certain operational conditions like constraint control.

(5) Yes. Only under reserve or transmission scarcity conditions.

(6) Extended LMP took effect in 2015 (150 FERC ¶ 61,143). Planning to implement ELMP Phase II to apply fast-start pricing to more peaking resources.

(7) No. But does allow inclusion of no-load costs in mitigated energy offer curves for unit commitment.

(8) No. But does allow inclusion of start-up costs in mitigated energy offer curves for the unit commitment.

(9) Yes, if offered into day-ahead market.

(10) Implementing fast-start pricing to commit quick-start resources more efficiently in real-time in Q2 2017.

ERCOT (Not subject to FERC NOPR)	**Start-up:** 10 minutes or less. **No minimum run time** requirement (11) (17)	Yes (12)(13)	Yes (13)(14)	Yes (15)	Yes (13) (16)	Yes

(11) Resource is exempted from following instructions for the first five-minute dispatch. Regulation reserves are used to cover missing energy.

(12) Yes. Market participants may include no-load costs in energy offer curves.

(13) Uplift may occur in cases in which the assumptions built into the energy offer curves are not correct and costs are not fully recovered.

(14) Yes. Market participants may include startup costs in energy offer curves.

(15) Yes. Day-ahead market is voluntary. Market participants may include no-load and start-up costs in energy offer curves.

(16) Market participants may include no-load and start-up costs in energy offer curves.

(17) Analyzing the feasibility and benefits of implementing a multi-interval real-time market.

Source: FERC and RTOs, ISOs

FERC NEWS

FERC Declares Montana QF Requirements Illegal

By Michael Brooks

FERC on Thursday declined to grant a solar developer's petition to enforce the Public Utility Regulatory Policies Act in Montana, where state regulators in June suspended a utility's tariff for qualifying solar facilities above 100 kW (EL17-5).

As a result, solar developer FLS Energy can sue the Montana PSC or NorthWestern Energy in federal court, if it chooses.

But FERC did find that the Montana Public Service Commission violated PURPA by requiring that qualifying facilities have power purchase agreements and interconnection agreements with utilities to form a legally enforceable obligation.

The Montana PSC voted 3-2 to suspend NorthWestern's tariff, finding that the avoided cost rate the utility was required to pay QFs was too high. The PSC grandfathered in facilities that had completed their agreements prior to the date of the order, June 16.

In its complaint filed in October, FLS said it had completed PPAs, but not interconnection agreements, for 14 QFs in the state. It accused NorthWestern of slow-walking the interconnection process while it lobbied the PSC for the tariff suspension.

Independent Power Systems

As a result of the suspension, the North Carolina-based company said it stands to lose $750,000, as it would have to negotiate new PPAs with NorthWestern, likely at a lower rate.

Under PURPA, utilities are obligated to purchase electricity from QFs, but each state can determine when a legally enforceable obligation begins, as long it does not conflict with FERC's regulations.

"We find that, just as requiring a QF to have a utility-executed contract, such as a PPA, in order to have a legally enforceable obligation is inconsistent with PURPA and our regulations, requiring a QF to tender an executed interconnection agreement is equally inconsistent with PURPA and our regulations," FERC said. "Such a requirement allows the utility to control whether and when a legally enforceable obligation exists — e.g., by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement."

FERC's order did not comment on the merits of the PSC's suspension itself, which FLS had also requested. The commission last month tossed out the same complaint by solar advocates, saying only QFs can seek PURPA enforcement. (See FERC Rejects Complaint on Montana Solar; 2nd Case Pending.)

In a footnote, however, FERC said, "When a state commission believes that a previously determined avoided cost rate is no longer an accurate measure of a utility's avoided costs, the appropriate response is not to establish a standard for a legally enforceable obligation that is inconsistent with PURPA and the commission's regulations under PURPA, but instead to determine a new avoided cost rate that better reflects the utility's avoided costs."

"This is a great win for our company and the QF community," Steven Levitas, vice president of business affairs and general counsel for FLS, said in an interview. "We were confident that the Montana commission's [legally enforceable obligation] was inconsistent with PURPA."

Levitas said that the company hopes the PSC will change the standard to comply with PURPA. Otherwise, he said, the company is prepared to take it to court.

FERC did not address FLS's accusation that NorthWestern violated interconnection procedures, saying that, as a Federal Power Act matter, it was beyond the scope of the complaint.

FERC: Let Fast-Start Resources Set Prices

Continued from page 24

SPP said it will be implementing fast-start pricing to commit quick-start resources more efficiently in real time in the second quarter of 2017.

PJM was criticized by its Independent Market Monitor, which said that relaxing eco mins for price setting is subjective and overrides "fundamental pricing logic," sometimes increasing total production costs.

The RTO also was criticized for limiting its fast-start definition to combustion turbines and excluding reciprocating engines.

"A natural gas-fired reciprocating engine that has a cold start-up time of only five minutes and has an economic minimum of 50% of its economic maximum is much, much more flexible, and provides significantly more value to the bulk electric power grid, on a per-megawatt-hour basis, than an inflexible block-loaded resource that takes two hours to start," IMG Midstream and Tangibl said in comments to the commission.

ERCOT, which is not subject to the FERC NOPR, is analyzing the feasibility and benefits of implementing a multi-interval real-time market.

Comments Sought

The commission asked stakeholders to comment on its proposals, including whether they could result in the exercise of market power. "The concentrated ownership of fast-start resources could raise market power concerns that are not addressed in existing RTO/ISO market power mitigation procedures," FERC said.

The commission also acknowledged that the changes could require complex and expensive software changes. "We seek comment on the required software changes, updates to optimization modeling and parameter inputs, estimated costs and time necessary to implement" the changes, FERC said.

Comments are due 60 days after publication in the *Federal Register*.

Stakeholder Soapbox

Rockland Electric: The Case for Preserving Seasonal Resources in PJM

By Shelly Lyser and Joel Yu

Summer resources in PJM's market are approaching a tipping point. After April 2017, resources such as demand response and solar generation will effectively no longer be able to participate in PJM's capacity market. As a result, they will no longer be able to earn the revenues that many rely on to stay in operation and to remain available during periods of peak customer demand.

This outcome is precipitated by PJM's requirements that all resources meet strict winter performance requirements, or otherwise partner with winter-performing resources like wind generation, in order to bid into its next three-year forward capacity auction.

Unfortunately, electric customers will bear the brunt of these unnecessary changes. With a summer-peaking system, PJM has built a requirement that leaves valuable resources out of the market and exposes electric customers to potentially higher prices. This concern led Rockland Electric, a subsidiary of Consolidated Edison, to partner with a diverse coalition, including environmental groups and DR providers, to protest this arrangement.

PJM has recognized this problem regarding retention of seasonal resources, and they have made moves to prevent the undesirable outcome. (See *PJM to Seek FERC OK for Seasonal Capacity Proposal*.) Under a recent proposal pending before FERC, PJM would make certain modifications to its summer-winter resource aggregation approach (ER17-367). However, past auctions have not yielded any viable participants in its resource aggregation program.

Musical Chairs

Even if all seasonal resources participated, aggregation can never fully solve the problem: Nearly 10,000 MW of summer-only DR and approximately 300 MW solar generation currently participate, in contrast to the 2,300 MW of available wind generation.[1] In the best-case scenario, with perfect aggregation, up to 8,000 MW of summer-performing resources are left with no winter aggregation partner. Like a game of musical chairs, when the music stops, some participants have no place to land. A mismatch exists, and the issue cannot be fully solved by aggregation.

The loss of summer resources will likely result in a significant cost impact to customers. PJM's Independent Market Monitor estimated that without seasonal resources, costs could increase between $1 billion to $5 billion across PJM. Besides the customer impacts, the market will also lose some of its cleanest sources of generation. Unlike year-round DR resources that typically have backup generators, summer-only DR often relies on reductions in onsite consumption, such as by lowering air conditioning. Solar generators previously allowed to participate based on their higher summer output also will be excluded, absent pairing with scarce winter resources.

These cross-cutting issues motivated Rockland Electric to join environmental groups, including the Natural Resources Defense Council and the DR industry group Advanced Energy Management Alliance, in a joint protest at FERC. In separate responses, state agencies and other energy companies also expressed displeasure with PJM's proposal and the loss of summer resources.

FERC Support Should not Waver

FERC has historically supported demand-side resource and renewable generation participation in wholesale markets. FERC proposed a rule in November that would open up access for smaller resources like batteries, which often have limited runtimes, to wholesale market revenues. In Orders 719 (2008) and 745 (2011), FERC enabled market participation by DR, while recognizing its benefits for creating just and reasonable rates. Through Order 764, FERC encouraged promulgation of market rules to better include variable energy resources. Allowing PJM to block access to these summer-only resources would undermine past efforts and effectively dismantle one of the country's largest DR markets. Instead of allowing PJM's untested approach, FERC should direct PJM to return to their summer, winter and annual resource comparability standards.

Shelly Lyser and Joel Yu are senior energy policy advisors for Rockland Electric. Rockland Electric, a wholly owned subsidiary of Orange and Rockland Utilities, which in turn is owned by Consolidated Edison Inc., is a transmission owner within PJM.

[1]PJM aggregation filing, pg. 21. https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=14400145

Company Briefs

Q3 2016: Best Quarter Ever for US Solar Industry

The U.S. installed 4,143 MW of solar PV in the third quarter of 2016, increasing 99% over the previous quarter and 191% over the same period last year, according to GTM Research in its "U.S. Solar Market Insight" report, published in conjunction with the Solar Energies Industries Association.

Q3 2016 was the largest quarter ever for the U.S. solar industry, according to the report. On average, a new megawatt of solar PV capacity came online last quarter every 32 minutes, the report said.

More: *Greentech Media*

Developer Eyes 10 Dams For Hydropower Renaissance

Boston-based Rye Development has proposed to build hydropower plants at Emsworth Back Channel dam and nine other dams in West Virginia and Pennsylvania that could come online in 2019, if approved. The development plan is part of what some see as a "renaissance" for a largely untapped source of renewable energy.

The U.S. Department of Energy says hydropower could grow by 50% over the next three decades. Presently, only 3% of the nation's 80,000 dams have hydropower installations on them.

It is unknown how President-elect Donald Trump's presidency would impact hydropower construction, as Trump has vowed to do away with President Obama's Clean Power Plan, which provides incentives for states to construct hydropower plants.

More: *West Virginia Public Broadcasting*

Exelon Hiring 400 at Clinton, Quad Cities

Exelon announced Wednesday it will hire more than 400 people to fast track multiple capital projects at its Clinton and Quad Cities nuclear power plants.

The announcement comes one week after Illinois Gov. Bruce Rauner signed the Future Energy Jobs Bill into law. The new law keeps both plants open for at least 10 years and provides Exelon with $235 million per year as a reward for the carbon-free energy produced by its nuclear reactors.

More: *Dispatch-Argus*

Xcel's Community Solar Gardens Hit with Delays

Xcel Energy has experienced delays in its plans to build two community solar gardens in western Wisconsin that were supposed to begin generating power by the end of this year.

The company announced in February that it would build 1-MW arrays in La Crosse and Eau Claire counties with the possibility of a third to be added later, but the utility had to abandon the La Crosse site.

Xcel has settled on a new site in Sparta but needs to secure the necessary permits. Construction is delayed at the Eau Claire site.

More: *La Crosse Tribune*

Appalachian Proposes Renewable Energy at High Price

Appalachian Power is proposing to offer 100% renewable energy to its ratepayers — but the price would be significantly above the going rates for wind in PJM.

Under the proposal, the average weighted cost of the renewable energy would be about $72/MWh. By comparison, the average cost of wind power purchase agreements nationally in 2015 was $20.75/MWh.

The proposal also stipulates that third-party sales of electricity throughout the utility's monopoly service territory would be prohibited.

More: *Southeast Energy News*

PG&E Review Finds Failure to Protect Against Moisture in Pipeline

Pacific Gas and Electric's review of an outage that affected 6,000 gas customers on one of the coldest days in December 2015 found that the utility did not adequately consider the risks associated with liquid or moisture intrusion into the gas system.

The problem began when a regulating station that reduces pressure on natural gas lines became frosted over and its pressure became "erratic."

PG&E traced the cause to a bypass valve that was improperly left open, thus preventing natural gas flowing from its storage facility from passing through equipment designed to remove moisture from the gas as it moves into PG&E's pipeline network.

More: *KQED*

Ameren Missouri Ramps Up Sulfur Dioxide Monitoring for Labadie

Ameren Missouri has agreed to install two additional air monitors near its coal-fired Labadie Energy Center in January and will use them, along with two already in operation, to determine if the plant complies with federal safety standards for sulfur dioxide.

Ameren maintains it is complying with sulfur dioxide emissions standards, which EPA announced six years ago.

But critics say Ameren's two existing air monitors are not located in areas with maximum concentrations.

More: *The Associated Press*

Duke Energy Denies Improperly Holding Up Solar Connections

Duke Energy Progress and Duke Energy Carolinas are denying allegations in complaints filed with state regulators that they violated North Carolina and federal utilities laws by holding up connections for three solar projects.

O2 EMC filed the complaints in late October claiming Duke didn't respond in a timely manner to requests from three solar farms for interconnection agreements that would allow O2 to build them and connect them to the grid.

Duke said it has more new applications so far this year than it did in 2015, and it has gone from five part-time engineers processing them to 18 full-time. But it still can't keep up with the flood of proposed utility-scale solar projects that continue to seek connections in North Carolina.

More: *Charlotte Business Journal*

FEDERAL BRIEFS

UN: Terrorists Attempting Cyberattacks on Power Stations

Eliasson

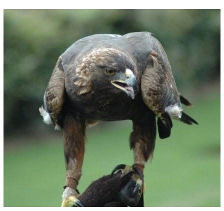
Terrorist groups are attempting to use cyberattacks to release radioactive material from nuclear power stations, the Deputy Secretary-General of the U.N., Jan Eliasson, warned at a meeting focused on how to prevent extremist groups from acquiring nuclear, chemical and biological weapons.

Several attacks on nuclear plants in Iran, South Korea and Germany have already taken place on a relatively small scale.

Cyberattacks can include efforts to obtain data on plant operations and personnel as well as "ransom attacks" in which the hackers seek money.

More: *The Independent*

Wind Turbine Rule Allows Death, Injury to Eagles



The Obama administration finalized a wind turbine rule last week that allows companies to kill or injure up to 4,200 bald eagles — nearly four times the current legal limit — without penalty.

Deaths of the rarer golden eagles would be allowed without penalty if companies take steps to minimize losses, such as retrofitting power poles to reduce the risk of electrocution.

The Fish and Wildlife Service estimates there are about 143,000 bald eagles and 40,000 golden eagles in the country. As many as 500 golden eagles a year are killed by collisions with wind towers, power lines, buildings, cars and trucks, Fish and Wildlife Service Director Dan Ashe said.

More: *The Associated Press*

Sierra Club Ad Ask Senators To Reject Trump's EPA Pick

The Sierra Club is launching a digital ad campaign costing at least $10,000 hoping to pressure senators to reject President-elect Donald Trump's nominee to head EPA.

The group is dubbing Trump's nominee, Oklahoma Attorney General Scott Pruitt, "Polluting Pruitt" because of his skepticism of climate change, his close work with oil and natural gas companies, and his record of suing the agency multiple times.

Pruitt

The group is targeting 10 senators and will run the ad in their home states for one week.

More: *The Hill*

Scientists Frantically Copy Climate Data Before Trump Takes Office

Banner for a "full day of hackathon activities in preparation for the Trump presidency." | *University of Toronto Technoscience Research Unit*

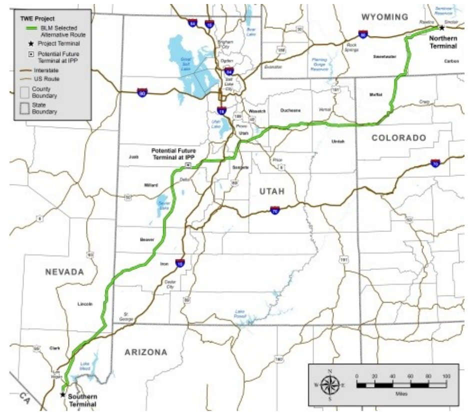
Fearing that climate data could vanish under President-elect Donald Trump's administration, scientists are racing the clock to copy government data onto independent servers.

Efforts have included a "guerrilla archiving" event in Toronto, meetings focused on how to download as much federal data as possible, and a collaboration between scientists and database experts to compile an online site for storing scientific information.

"Something that seemed a little paranoid to me before all of a sudden seems potentially realistic, or at least something you'd want to hedge against," said Nick Santos, an environmental researcher at the University of California at Davis. Santos spent his weekend copying government climate data onto a nongovernment server, where it will remain available to the public.

More: *The Washington Post*

BLM Approves TransWest Express Tx Project



TransWest Express

The U.S. Bureau of Land Management has approved the TransWest Express Transmission Project, which will add 3,000 MW of capacity between the Desert Southwest and Rocky Mountain regions.

BLM-managed land represents about 60% of the project's 730-mile route.

The project will extend from south-central Wyoming to the site of a potential interconnection near Delta, Utah, and then to the Marketplace Hub near Hoover Dam in southern Nevada, which provides interconnections to the California, Nevada and Arizona grids.

More: *TransWest Express*

Bill Gates, Other Investors Spending $1B on Clean Energy Development

Breakthrough Energy

Twenty investors — including Bill Gates, Mark Zuckerberg, George Soros and Richard Branson — plan to spend more than $1 billion on developing technologies that will reduce greenhouse gas emissions and lower the price of energy.

Gates is the chairman of the group, called Breakthrough Energy Ventures. The coalition formed in 2015.

The Microsoft founder said the fund plans to hire staff and make initial investments in 2017. The group wants to target startups that can reduce emissions from electricity generation, transportation and industrial processes in steel-making, cement production and agriculture.

More: *The Associated Press*

STATE BRIEFS

ARIZONA

Regulator Wants Nuclear Counted As Renewable Power Source


Tobin

A state utility regulator is proposing a "Clean Peak Standard" that would count nuclear energy as a renewable power source, effectively reducing the amount of solar, wind or other resources utilities need to meet the state's renewable energy goal.

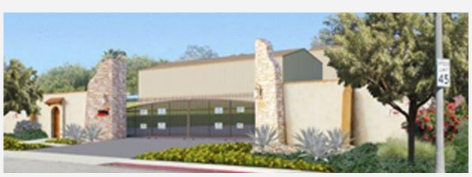
Under the state's Renewable Energy Standard and Tariff, utilities must get 15% of their power from renewable sources by 2025. The chairman of the Corporation Commission has proposed doubling that standard.

"The Clean Peak Standard offers great promise in moving the commission away from an obsolete commitment to arbitrary renewable energy goals that ignore significant zero-emission resources like Palo Verde Nuclear Generating Station or other emerging technologies like energy storage," Commissioner Andy Tobin wrote in a letter commenting on the commission's proposed doubling of the standard.

More: *The Arizona Republic*

CALIFORNIA

PUC Approves SDG&E Reliability Project in San Juan Capistrano



The Public Utilities Commission voted 5-0 to approve San Diego Gas & Electric's proposed $381 million new distribution facility in San Juan Capistrano.

The city had opposed expanding the electrical infrastructure in a residential neighborhood and the partial demolition of a 1917 historic substation in favor of two large metal buildings for housing transmission equipment.

Construction could begin as early as April and is expected to take more than four years to complete.

More: *The Orange County Register*

New Climate Change Laws May Reduce Jobs, Economic Output

The state's Air Resources Board projects a potential reduction of 25,000 to 102,000 jobs and the loss of $7 billion to $14 billion in gross state economic output as a result of two new climate change laws signed by Gov. Jerry Brown.

Senate Bill 32 requires the state to cut greenhouse gases 40% below their 1990 level, and Senate Bill 1383 requires similar reductions in methane, refrigerant gases and black carbon.

Presently, the state is spending about $2 billion on energy efficiency and renewable energy programs, according to the Legislative Analyst's Office.

More: *Los Angeles Times*

CEC Approves Nation's First Computer Energy Efficiency Rules

In a move that will cut greenhouse gas emissions by 700,000 tons per year, state regulators Wednesday adopted the nation's first energy efficiency rules for computers and monitors. The devices are responsible for 3% of home electric bills and 7% of commercial — much of that while they sit idle.

The rules will be implemented in three phases. The first phase begins in January 2019 with desktop, laptop and notebook computers. The second phase kicks in for workstations and small-scale servers in January 2018. Standards for computer monitors start in July 2019.

When fully implemented, the industry-backed plan will save consumers $373 million a year, according to the state Energy Commission.

More: *Reuters*

KENTUCKY

Big Rivers Deal Powers 9 Cities, Stabilizes Rates

State utility regulators have approved a 10-year power supply contract between Big Rivers Electric and the Kentucky Municipal Energy Agency in which Big Rivers will provide 100 MW for nine cities beginning June 2019.

In 2013 and 2014, aluminum smelters in Hawesville and Sebree — which provided two-thirds of Big Rivers' load and revenue — stopped purchasing power from utility. The loss left Big Rivers with excess generating capacity and caused rate increases.

The contract, which could be expanded to include an additional 50 MW, will help stabilize prices for Big Rivers' native load customers served by its three member-owners: Jackson Purchase Energy, Kenergy and Meade County Rural Electric Cooperative.

More: *The Gleanor; The State Journal*

MICHIGAN

State Rep. Trying to Stop Palisades Plant from Closing


Nesbitt

The chair of the state House Committee on Energy Policy has sent letters to Consumers Energy, Entergy and MISO imploring them not to prematurely terminate a power purchase agreement and eventually close the Palisades nuclear power plant.

The PPA between Entergy and Consumers was supposed to be through 2022, and the plant is licensed to operate into the 2030s.

In his letters, State Rep. Aric Nesbitt said the move puts the state's electric reliability into question and is a "sucker punch" to the plant's hard-working employees and the community.

More: *WSJM*

MINNESOTA

Interim Rate Hike Approved; More Rate Hikes on the Horizon

State regulators last week approved a 5.6% interim rate increase for most Minnesota Power customers while the utility awaits the outcome of a 12- to 18-month hearing process on its request for a long-term 18% rate hike.

The interim rate increase, which starts in January, is less than the 8% the utility had requested.

Minnesota Power has also proposed an

Continued on page 31

State Briefs

Continued from page 30

additional 10% increase for homeowners — on top of the 18%. The proposed 10% increase is part of a rate shift the utility is seeking due to a push by the Legislature to lower rates for taconite plants and paper mills.

More: *Duluth News Tribune*

NEVADA

Las Vegas Reaches Finish Line on Clean Energy Goal

Las Vegas municipal facilities are now powered 100% by renewable energy sources, a goal that was pushed to the finish line when Boulder Solar 1, the large-scale project near Boulder City, went online last week.

The city began implementing its sustainable energy programs in 2008 and has reduced its energy consumption by more than 30%, said Tom Perrigo, the city's planning director and chief sustainability officer. As part of the program, solar arrays were placed on and around city facilities where it made sense.

The city is saving roughly $5 million annually because of the shift to renewable energy.

More: *Las Vegas Review-Journal*

NEW HAMPSIRE

Businesses Cite High Energy Costs as Reason to Look Elsewhere

Federal government statistics rank the state as having the seventh-highest commercial electric rates in the continental U.S. and the fifth-highest industrial rates — and industrial leaders, including Whelen Engineering, Sig Sauer and Lindt & Sprungli, are citing that as a reason for setting up operations elsewhere.

In September, the average energy price for commercial users in the state was 14.41 cents/kWh, compared with 9.67 cents in Georgia and 8.33 cents in Arkansas. Industrial users pay 12.33 cents/kWh in the state, 6.18 cents in Georgia and 6.42 cents in Arkansas, according to the U.S. Energy Information Administration.

"If we don't have an assurance of reliability and a drastic reduction in our energy costs, a lot of us will be packing our bags and going," said John Olson, Whelen Engineering's executive vice president.

More: *New Hampshire Union Leader*

NEW MEXICO

PNM Rate Hike Continues Pending Outcome of Appeal

The state Supreme Court has ruled that Public Service Company of New Mexico customers must continue paying a 9% rate increase approved by state regulators earlier this year while an appeal by the utility seeking more money is pending.

PNM originally asked state regulators for a $123.5 million annual rate increase, but received $65.7 million.

Opponents of the increase are expected to argue on appeal that PNM should have received less. Supreme Court Justice Petra Jimenez Maes has indicated that PNM must reimburse customers if the court ultimately rules against part or all of the rate hike.

More: *The Santa Fe New Mexican*

NEW YORK

ESCOs Barred from Selling To Low-Income Customers

The state has banned energy service companies from selling natural gas and electricity to low-income customers after finding they have been overcharging by hundreds of millions of dollars.

Low-income customers constitute 30% of the state's utility market and are eligible for government subsidies.

"The state has a duty to protect low-income customers from unscrupulous business practices," Public Service Commission Chair Audrey Zibelman said.

More: *Times Union*

NORTH DAKOTA

Law Enforcement to Obama: Send Help to Police Pipeline

A dozen law enforcement officials in the state have asked President Obama to send 100 Border Patrol agents, members of the U.S. Marshals Service Special Operations Group and an unspecified amount of financial assistance to help local police during protests against the Dakota Access oil pipeline.

"If we do not receive federal assistance, the safety and well-being of law enforcement officers, citizens of the community and the protesters themselves are at grave risk," stated a letter spearheaded by Morton County Sheriff Kyle Kirchmeier.

Nearly 575 pipeline opponents have been arrested since August, and law enforcement officials expressed concerns that area residents will "take matters into their own hands" after months of disruptions by protesters.

More: *The Associated Press*

OHIO

Utilities Commission Looking to Fill 2 Seats


Petricoff

Two of the five seats on the state's Public Utilities Commission are up for grabs.

Commissioner Lynn Slaby's seat will become available when his term ends in April. Commissioner Howard Petricoff, who was appointed in June by Gov. John Kasich, announced his resignation this month after a Senate committee said it did not recommend his appointment, citing the potential for conflicts of interest.

Applications are due to the nominating council by 5 p.m. on Jan. 12.

More: *Columbus Business First*

Dayton Power Seeks $1B PUCO Bailout

Like FirstEnergy and American Electric Power before it, Dayton Power and Light is requesting from state regulators a seven-year distribution modernization rider totaling $1 billion to maintain its financial integrity in the face of a falling credit rating, "anemic growth load" and "historically low market prices." The requested rider would run from Jan. 1, 2017, to Dec. 31, 2023.

DP&L requested the rider in an Oct. 11 amended application to the Public Utilities Commission for approval of its electric security plan. If the application becomes

Continued on page 32

STATE BRIEFS

Continued from page 31

law, regulators could change DP&L's electric rates if the company's financial health is at stake.

"We don't dispute that DP&L is on the brink of serious financial issues, but we question customers having to bear the brunt of $145 million per year," said Trent Dougherty, general counsel with the Ohio Environmental Council. "You're opening a Pandora's Box for utilities going to consumers to get funding."

More: Midwest Energy News

OREGON

Wind Project Planning Fewer, Larger Turbines

The Golden Hills Wind Project, in Sherman County, could produce the same 400 MW of energy with fewer — but larger — turbines under changes proposed by its developer.

Golden Hills Wind Farm, a subsidiary of Orion Renewable Energy Group, initially sought to build the project with 267 turbines with a total height, including the rotor blades, of 420 feet. The firm was granted a site certificate in 2009. However, because of changes in turbine technology, Golden Hills now wants to build 125 turbines with a total height, including the rotor blades, of 518 feet.

The state Energy Facility Siting Council could consider the changes at a meeting in early 2017. Construction would start in June 2018 and end in June 2021.

More: The Bulletin

SOUTH DAKOTA

Deep Drilling Project Stokes Fears of Nuclear Waste Storage

A proposed scientific research experiment to drill an 8-inch borehole 3.2 miles into solid granite in Haakon County has residents fearing a successful test could lead to the eventual storage of nuclear waste.

RESPEC, an engineering consulting firm formed in 1969 by six professors from the South Dakota School of Mines and Technology, would drill the hole — the deepest ever drilled in the state — to learn how to drill basement rock for nuclear storage.

Gov. Dennis Daugaard said the proposed experiment should in no way lead residents to believe he supports storing nuclear waste in the state.

More: Rapid City Journal

Both Sides of Wind Farm Debate Want Voters to Settle the Issue

Both sides to the debate on whether Dakota Power Community Wind should be allowed to build a 400-MW project in Lincoln County have indicated they would like voters to decide the issue — and both believe the votes would be in their favor.

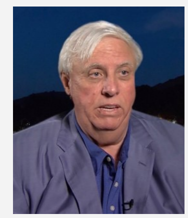
The County Commissioners are scheduled to consider at a Dec. 27 meeting wind turbine rules that would make going forward with the project impossible.

A referendum would require collecting at least 1,732 valid signatures within 20 days of when the commission's final decision is formally published.

More: Argus Leader

WEST VIRGINIA

$900K Penalty, Pollution Reductions For Governor-Elect's Coal Mines


Justice

A U.S. District Judge has approved a settlement requiring a $900,000 civil penalty and pollution reductions by Appalachian coal mines owned by Governor-elect Jim Justice.

The settlement, with Southern Coal Corp. and 26 affiliates, resolves alleged violations of the Clean Water Act at Justice's mines in locations including the state, Alabama, Kentucky, Tennessee and Virginia.

Under the settlement, Southern Coal must use an EPA-approved environmental management system, undergo compliance auditing, implement data tracking and pay escalating penalties for future violations.

More: The Associated Press

Michigan Energy Bill Preserves RPS, 10% Retail-Choice Cap

Continued from page 1

policy since 2008, the legislation:

- Sets a 15% renewable standard by 2021, up from the current 10%, while broadening the eligibility to include geothermal and pump storage;
- Sets a nonbinding goal of meeting 35% of the state's energy needs through renewables and energy efficiency by 2025;
- Maintains the state's 10% retail-choice cap;
- Creates a "backup plan," in case MISO's proposed forward capacity auction for its competitive retail areas is rejected by FERC or proves too expensive;
- Adds cost controls to the utilities' required integrated resource plans; and
- Allows utilities to offer competitive "value-added" services to supplement rate-base revenue.

Snyder took to his official YouTube channel Thursday to tout the bill, which he said would address concerns of a capacity shortfall. The state expects to lose 5,000 MW of coal-fired generation over the next seven years — pushing the state's reserve margin down to 15%. Over the next 15 years, the state could lose 30% of its generation.

"What we're in is a huge transition in how we get our energy," Snyder said. "We've got a lot of aging coal plants that are beyond their useful life, and it's not worth investing in them anymore. … We can transition to both natural gas and renewables and let the markets sort of define the balance between those two, so we're moving away from an old energy source [where] we had to import all of this coal."

Snyder also said he hoped the legislation would lead to more investment in solar power.

Capacity 'Backup Plan'

To ensure the state has adequate capacity, the legislation requires a "much more robust" integrated resource planning process, said Greg Moore, legislative

Continued on page 33

Michigan Energy Bill Preserves RPS, 10% Retail-Choice Cap

Continued from page 32

director for state Sen. Mike Nofs, one of the authors. Utilities will have to prove generation they build or buy is "the most reasonable and prudent" alternative. The IRPs, which must be filed every five years, will be expected to include provisions for energy efficiency, distributed generation and demand response, Moore said.

The bill also requires the Public Service Commission to conduct a contested hearing on whether a state capacity charge is "more cost-effective, reasonable and prudent" than MISO's proposed forward capacity auction in meeting the RTO's local clearing and the planning reserve margin requirements. If FERC fails to approve the forward auction by Sept. 30, 2017, the PSC will establish a "state reliability mechanism," including a capacity charge. (See related article, *MISO Forward Auction Filing Draws Protests*, p.12.)

The commission would make separate findings for each utility service territory. If the commission implements a state capacity charge, it would remain in effect for at least four planning years unless that conflicts with the FERC ruling on MISO's proposal.

MISO spokesman Jay Hermacinski said the RTO had no comment on the bill. "We really need to see what FERC's going to do," he said. "Once FERC's made its decision then we'll move forward. As we've done the last year and a half, we'll be working with Michigan to come up with the best solution possible."

Consumers Energy HQ

Gratiot Wind Farm | *DTE Energy*

The PSC also was directed to conduct a proceeding within one year on whether customers participating in net metering or distributed generation program should be charged a grid usage fee. It will consider both the costs net metering customers impose on the grid and the benefits they provide, said Moore.

Retail-Choice Compromise

Some House Republicans had threatened to oppose the bill, fearing that a proposed capacity charge on competitive suppliers would kill the state's retail-choice program. The state's dominant utilities, DTE Energy and Consumers Energy, had sought the charge, accusing their competitors of being free riders.

"The question is how do you balance these all out, and I'm proud to say we got all of these groups largely to come to a strong agreement by finding some good middle ground," Snyder said.

The legislation bars retail customers who return to their home utility after using an alternate supplier from returning to a competitor for six years. It also stipulates that if competitive suppliers lose customers and demand dips below the 10% threshold, the new, lower retail-choice percentage would become the new cap for six years. The competition program reportedly has a waiting list of about 11,000 customers.

Notwithstanding the cap, customers currently receiving all of their power from competitive suppliers would be able to increase their competitive loads at the existing or adjacent facilities.

Utilities would be allowed to supplement their rate-base revenues through "value-added" programs and services "if those programs or services do not harm the public interest by unduly restraining trade or competition in an unregulated market."

Reaction

DTE and Consumers both commended the bills' passage.

DTE praised the increased renewable mandates and preservation of the state's retail-choice market while adding reliability obligations. "It addresses these issues in a fair and constructive way and provides a framework for the state to plan for its own energy future," DTE said in a statement.

Consumers said the "sound energy policy legislation [ensures] that our state has a comprehensive plan for ensuring electric reliability and affordable and sustainable energy going forward."

The Michigan Environmental Council said the final bill was a "vast improvement" over earlier proposals that would have eliminated the RPS. "This deal will save millions of dollars a year for Michigan residents by continuing to eliminate energy waste and increasing investments in wind and solar power, which are the cheapest ways to produce electricity," the group said.

The conservative Michigan Freedom Fund said the revised package "eliminates every anti-choice 'poison pill'" in earlier versions of the legislation.

Although the bills ultimately won broad bipartisan support, not everyone was happy with the result. Republican Sen. Patrick Colbeck told Detroit station WXYZ that the bills were rushed through and that he did not support leaving electricity cost decisions in the hands of the PSC.

Michigan Upper Peninsula Getting its Own Utility

MISO to Study Michigan Reliability

By Amanda Durish Cook

Michigan's Upper Peninsula will get its own utility, two new generating plants — and maybe additional transmission — following actions by regulators and MISO officials seeking to address the region's reliability and cost concerns.

MISO said Wednesday it has committed to a study examining the benefits of transmission connection between Ontario and Michigan's Upper and Lower Peninsulas. The announcement followed the Michigan Public Service Commission's Dec. 9 order approving the creation of the Upper Michigan Energy Resources Corp. (UMERC) (Case No. U-18061).

The company will be formed from the electric and gas distribution assets of Wisconsin Electric Power Co. (WEPCo) and Wisconsin Public Service — both subsidiaries of Milwaukee-based WEC Energy Group — and will begin serving about 40,000 Upper Peninsula customers Jan. 1.

The terms of UMERC's creation were negotiated under a settlement signed by the companies, PSC staff, Attorney General Bill Schuette, Tilden Mining, Cloverland Electric Cooperative and others.

No Cost Sharing

PSC spokeswoman Judy Palnau said the new utility will avoid cost-sharing with Wisconsin, as it will be regulated by Michigan alone.

The utility will be the owner and operator of two new proposed generating facilities expected in operation by 2019, one year before the Presque Isle plant in Marquette shutters. UMERC will depend on power purchase agreements with WEPCo and WPS until the new generation is operating.

The commission said rates and service for Upper Peninsula customers should not be adversely affected by the changes.

"The transition to UMERC for ratepayers will be as seamless as possible. The commission observes that the personnel currently responsible for management, communications, regulatory compliance and customer relations will not change. Moreover, the PPAs will offer reasonable and affordable rates that may indeed, as the record indicates, be slightly lower than recent rates," the order said. "The commission is also persuaded that the settlement protects

Presque Isle

ratepayers from any rate impact associated with the termination of Tilden as a customer, whether voluntary or involuntary. The settlement represents the beginning of the process of ensuring that reliable and affordable power is available over the long term in the UP."

WEC spokeswoman Amy Jahns said the new utility would not have employees "specifically" assigned to it; instead, WEC's office in Iron Mountain, Mich., and its WPS office in Menomonee, Mich., "will provide services to support the new utility."

Jahns said the company is awaiting approvals regarding UMERC from the Wisconsin Public Service Commission and FERC.

Conditions Attached

The PSC's approval came with several conditions, including that Michigan PSC staff receive UMERC's yearly capital reports and operations plans and have access to all of WEPCo's books and records concerning the 431-MW Presque Isle plant when the commission reviews the plant for decommissioning and final cost recovery from ratepayers.

WEPCo and WPS are also barred from changing any of the terms of their PPAs until Jan. 1, 2020. The companies also cannot request FERC to shift "any costs to UMERC customers that are currently shared between Wisconsin and Michigan."

UMERC plans to build two natural gas-fired plants totaling 170 MW in the Upper Peninsula to provide power in the absence of the Presque Isle plant. WEC will seek permission from the PSC to build the plants next year. (See *Upper Peninsula Ratepayers to Seek FERC Probe of Billing Fraud*.)

PSC staff and Schuette supported the utility's creation after the PSC obtained additional information in November on whether the proposal would have an adverse impact on customer rates.

Reliability and costs have long been concerns in the sparsely populated Upper Peninsula. Until recently, the area was home to a trio of system support resource agreements with MISO that kept retiring coal units online. Last month, FERC ruled that MISO and American Transmission Co. could reconfigure the western Upper Peninsula transmission system into two load pockets to end the last of the three SSRs. (See *MISO Allowed to End White Pine SSR*.)

MISO Agrees to Michigan Reliability Studies

At last week's Planning Advisory Committee meeting, MISO committed to a pair of reliability study requests submitted earlier this year by Michigan officials.

One will examine the benefits of transmission between Ontario and Michigan. The second will evaluate resource adequacy in MISO's Local Resource Zone 7 in Lower Michigan under a scenario without either the Palisades or Fermi nuclear plants. Earlier this month, Entergy and Consumers Energy announced they intend to mothball the Palisades nuclear plan in southwestern Michigan on Oct. 1, 2018. (See *Entergy, Consumers Announce Closure of Palisades Nuke*.)

The studies were requested this summer by Michigan Gov. Rick Snyder, who asked the RTO to determine whether transmission linking northern Michigan to Ontario could improve reliability and reduce costs. (See *Michigan Asks MISO to Study Tx Links to Ontario*.)

"Generally when we get a request from a state, we try to be responsive as we can because we do believe that's part of our role," MISO Director of Planning Jeff Webb said.

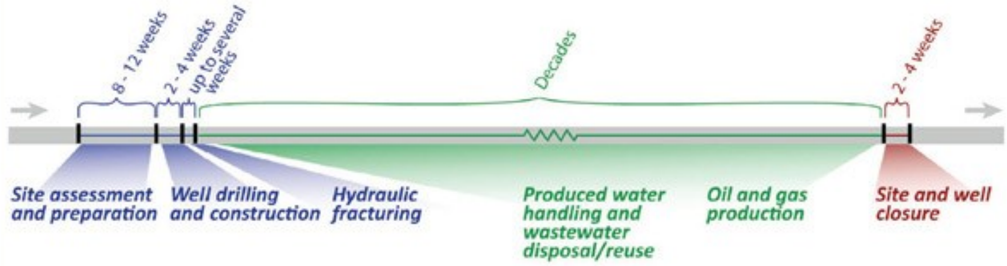
MISO engineer Adam Solomon said the first phase of the studies are already underway and expected to be completed as part of the 2017 Transmission Expansion Plan's batch of studies using Electric Generation Expansion Analysis System (EGEAS) modeling. Solomon said while the studies will "kind of overlap MTEP 17, [they are] not necessarily contained within."

MISO Director of Regional and Economic Studies John Lawhorn said that although the studies will be treated separately, they are related to Michigan's reliability concerns. "The results of one study will influence the other," he said.

Lawhorn said the second phase of the studies, a transmission analysis, would begin early next year.

EPA: Poor Fracking Practices Have Harmed Drinking Water

Continued from page 1



General timeline and summary of activities at a hydraulically fractured oil or gas production well. | *EPA*

The report identifies conditions under which impacts can be more frequent or severe, including:

- Water withdrawals in times or areas of low water availability, particularly areas with limited or declining groundwater;
- Spills of fracking fluids or wastewater involving large volumes or high concentrations of chemicals reaching groundwater;
- Injections into wells whose steel casing or cement lacked "mechanical integrity," allowing gases or liquids to escape;
- Injections directly into groundwater resources;
- Discharge of inadequately treated wastewater to surface water resources; and
- Disposal or storage of wastewater in unlined pits.

"This assessment is the most complete compilation to date of national scientific data on the relationship of drinking water resources and hydraulic fracturing," Dr. Thomas A. Burke, deputy assistant administrator of EPA's Office of Research and Development, said in a statement.

EPA said, however, the report "was not designed to be a list of documented impacts."

"Data gaps and uncertainties limited EPA's ability to fully assess the potential impacts on drinking water resources both locally and nationally. Generally, comprehensive information on the location of activities in the hydraulic fracturing water cycle is lacking, either because it is not collected, not publicly available, or prohibitively difficult to aggregate," the agency said. "In places where we know activities in the hydraulic fracturing water cycle have occurred, data that could be used to characterize hydraulic fracturing-related chemicals in the environment before, during and after hydraulic fracturing were scarce. Because of these data gaps and uncertainties, as well as others described in the assessment, it was not possible to fully characterize the severity of impacts, nor was it possible to calculate or estimate the national frequency of impacts on drinking water resources from activities in the hydraulic fracturing water cycle."

Done at the request of Congress, the report was based on a review of more than 1,200 cited scientific sources, new research conducted as part of the study and an independent peer review by EPA's Science Advisory Board. The board had been sharply critical of a 2015 draft that said the agency "did not find evidence that [fracking activities] have led to widespread, systemic impacts on drinking water resources" in the U.S.