RTO Insider
Your Eyes and Ears on the Organized Electric Markets
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New York Adopts Clean Energy Standard, Nuclear Subsidy

By William Opalka

An overflow crowd made up of residents, activists, environmentalists and the nuclear industry gathered in Albany to hear the New York Public Service Commission's decision. © *RTO Insider*

ALBANY, N.Y. — The New York Public Service Commission on Monday unanimously approved its Clean Energy Standard, including a controversial plan to prop up struggling upstate nuclear power plants with a 12-year subsidy that opponents say could cost ratepayers $7.6 billion (15-E-0302).

The order creates a zero-emission credit for nuclear plants similar to the way states incentivize renewable resources with an additional above-market payment. ZECs were a feature added earlier this year to the CES, which will require New York to derive 50% of its energy from renewable sources by 2030. Nuclear power, which currently provides 30% of the state's electricity, is seen as a bridge for its carbon-free attributes until renewable energy can

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FirstEnergy Posts $1.1 Billion Loss, Eyes Exit from Merchant Generation

By Ted Caddell

FirstEnergy on Friday posted a $1.1 billion second-quarter loss, much of it related to the pending closure of five coal-fired units, and CEO Chuck Jones said the company will not make any large investments to prop up its merchant generation business credit rating.

"We do not see baseload generation as a good fit for our company," Jones said during a call with analysts on Friday. The company will not rule out "the possible sale or deactivation" of additional units as wholesale energy prices continue to languish, he said.

The losses make the outcome of the company's two-year struggle with the Public Utilities Commission of Ohio to garner guaranteed income for its generators that much more critical.

On July 25, it filed testimony with PUCO saying that a staff-recommended plan for a

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Mass. Bill Boosts Offshore Wind, Canadian Hydro

DONG Energy offshore wind turbines *Source: DONG*

By William Opalka and Rich Heidorn Jr.

With only hours to go at the end of its session, the Massachusetts legislature Sunday night passed a major energy bill that boosts Canadian hydropower and offshore wind as sources to meet the state's clean energy goals.

Legislative negotiators worked through the weekend to reconcile House and Senate bills that differed over the volume of offshore wind, the inclusion of the Cape Wind project and support for new gas pipelines.

The final bill (H.4568) requires utilities to annually obtain 9,450 GWh of energy that qualifies for the state renewable portfolio standard, including onshore wind and Canadian hydropower.

It also orders procurement of 1,600 MW of offshore wind by 2027 — a compromise between the House's 1,200 MW and the Senate's 2,000 MW. It excludes Cape Wind, which the Senate would have included, be-

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NARUC Summer Meetings 2016

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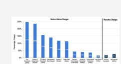

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FirstEnergy Posts $1.1 Billion Loss

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Distribution Modernization Rider of $131 million a year for three years wouldn't be enough to provide credit support to the company so it can maintain its investment-grade credit rating and begin grid modernization initiatives (14-1297-EL-SSO). (See *PUCO Staff Recommends $131M Annual Rider for FirstEnergy*.)

It also balked at staff's recommendation that the company be required to refund the subsidy if it moves from its Akron headquarters.

FirstEnergy has proposed a Retail Rate Stability rider that would provide it $558 million a year for eight years for credit support. Eileen Mikkelsen, vice president of rates and regulatory affairs, said the rider should be increased by an amount reflecting the economic development value of maintaining its headquarters in Akron.

In testimony filed July 22, Sarah Murley, an economic consultant hired by the company, said the headquarters has an annual economic impact of $568 million on Ohio's economy, based on the 1,360 employees there (an annual payroll of $151.3 million) and its support of an additional 2,047 jobs ($93.3 million in annual payroll) by other businesses throughout Ohio.

Critics said the RRS rider and the economics benefits adder FirstEnergy is seeking could result in more than $8 billion in ratepayer-funded subsidies if they lasted the full eight years.

Shannon Fisk, an attorney with Earthjustice, said the annual price tag could be as high as $1.126 billion, if PUCO grants the $558 million RRS rider and the $568 million the company claims as the economic development value of its operations.

"FirstEnergy is proposing that the DMR would last through May 31, 2024, almost eight years, so the total amount of captive customer money provided under FirstEnergy's proposal would be somewhere between $4 billion and more than $8 billion," Fisk said.

Generation Business Driving Losses

FirstEnergy's $1.1 billion loss represents $2.56/share on revenue of $3.4 billion. That compares with net income of $187 million, or 44 cents/share, during the same period last year.

In a news release, the company attributed the loss primarily to "asset impairment and plant exit costs in the company's competitive business," a reference to its recently announced plan to sell or close its Bay Shore plant near Toledo and retire four coal-fired units at its W.H. Sammis plant on the Ohio River. (See *FirstEnergy Closing Largest Coal Plant in Ohio; Bay Shore also in Peril*.)

It is with its eye on the corporation's credit rating that Jones said the company will be looking to concentrate on its regulated businesses and begin to look for ways to exit the merchant generation business in the coming years.

"Our long-term goal is to operate as a fully regulated company," he said. To illustrate its concentration on driving down generation costs, the company announced it was postponing by three years the expensive steam generator and reactor pressure head replacement at its Beaver Valley nuclear station in Pennsylvania, "and we've already identified $80 million in fossil fleet savings" annually going forward, he said.

Success Hinges on PUCO

Earlier in its negotiations with PUCO, the company proposed a 15-year period of guaranteed income for its struggling merchant plants. When that was denied, it came back with an eight-year plan, which was approved by PUCO but eventually jettisoned when FERC ruled that it would need to undergo federal review under the *Edgar* affiliate abuse test.

FirstEnergy withdrew its request and filed a modified request with PUCO that was not tied to any specific generation assets, with the understanding that it would not need FERC review. Critics have charged that it could cost customers between $3.6 billion and $4 billion.

The latest rider request would be an alternative to that plan.

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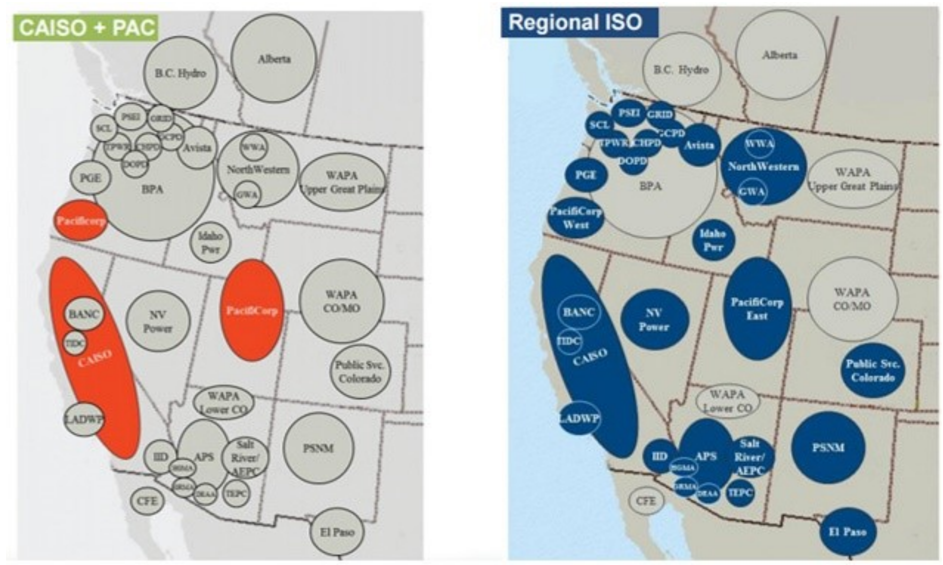
Correction

An article in last week's *RTO Insider* incorrectly stated that wind production surpassed nuclear production on ERCOT's system in 2014. The year was actually 2015.

CAISO NEWS

Governance Plan Critics Urge Slowdown of Western RTO Development

By Robert Mullin



"Two Visions of the Future": An expanded CAISO would first take in PacifiCorp's service territories, but the ISO is preparing for other transmission owners to join in the near future. *Source: CAISO*

Critics of CAISO's most recent draft proposal of principles for governing a Western RTO contend the ISO is moving too quickly to get a plan to California lawmakers before the close of the current legislative session in September.

Speaking at a joint state agency workshop in Sacramento on Tuesday, multiple industry participants expressed concern that the ISO's expedited effort to complete a proposal will result in a governance framework that defers too many issues to be resolved in the future.

The workshop — hosted by CAISO, the California Public Utilities Commission and the California Energy Commission — marked the last public forum in which stakeholders could discuss the proposal before it gets forwarded to Gov. Jerry Brown, who is expected to transmit a final version to lawmakers in August. California law requires the legislature to approve the ISO's transformation into an RTO, a process that would result in the state losing direct authority over the grid operator.

'One of the Largest Issues in CAISO History'

"Regionalization is one of the largest issues facing the ISO in its history," said Carolyn Kehrein, principal consultant for the Energy Users Forum, which represents large energy customers in California. "Unfortunately, the changes [to the original proposal] were made to meet a quick turnaround."

Among those changes were provisions that clarify the composition and responsibilities of a transitional committee tasked with creating a final governance plan; reaffirm that any such plan must respect individual states' sovereignty over electricity matters they currently regulate; and set a specific timeframe for the appointment of a final RTO board (See *Revised Western Governance Plan Highlights State Authority*.)

The revised proposal defined the makeup of a Western States Committee (WSC), which would consist of state-appointed representatives and two nonvoting members representing publicly owned utilities and federal power marketing administrations (PMAs). A provision requiring load-weighted voting on the WSC was altered to enable the transitional committee to develop a process that factors in "some form of weighted voting based on load," such as a supermajority requirement.

CAISO also added a provision for the RTO to adopt a capacity market at the request of member states, while eliminating a provision for tracking greenhouse gas emissions — a measure the ISO contended was more suited for inclusion in market operations than as a principle in an overarching governance plan. The GHG mechanism would have monitored carbon emissions from all thermal plants participating in the RTO, not just those located in California.

Western States Committee Powers

"Our biggest concern is — how many more revisions will there be before this is final?" said Matt Freedman, an attorney with The Utility Reform Network (TURN), which represents small customers. "This feels like a working draft."

Freedman said his organization was concerned that the WSC's powers were reduced in the revised proposal, which now stipulates that the RTO's board can — in certain circumstances — override the requirement for the committee's approval for Section 205 filings with FERC.

TURN was also worried about the "watering down" of an earlier prohibition on capacity markets, as well as the removal of the reference to GHG tracking.

Sierra Club staff attorney Travis Ritchie wondered how California would manage its GHG program without making emissions tracking a core principle, saying that the absence of tracking in the Energy Imbalance Market has allowed carbon leakage into the state's power market.

"We need to agree what our fundamental principles are before opening up this market," Ritchie said. "We have to set out our clear requirements first."

Tony Braun, an attorney representing the California Municipal Utilities Association (CMUA), criticized the proposal for deferring the decision to create an RTO market advisory committee to the transitional committee.

"We think the transitional committee scope is too broad," Braun said. "I don't think the states are going to go for it."

He cautioned the ISO not to move too quickly to advance a proposal to lawmakers given the number of "outstanding issues" related to governance.

'Shouldn't be Rushing'

"We shouldn't be rushing forward now. The

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CAISO NEWS

Governance Plan Critics Urge Slowdown of Western RTO Development

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train is not going to come off the tracks," Braun said. "Let's not get embedded in a discussion in the legislature this year."

"It seems to me that you're placing a heavy burden on the people in the building just north of this," said Imperial Irrigation District (IID) General Manager Kevin Kelley, referring to legislators in the nearby state capitol.

Kelley said that his utility, which operates its own balancing authority area in Southern California's Inland Empire region, is opposed to CAISO's regionalization because it will require the state to relinquish its oversight over an organization that suffered costly market manipulation during the 2000-2001 Western Energy Crisis. IID last month sued CAISO to force public disclosure of protected information related to the ISO-commissioned studies supporting regionalization.

Kelley suspected the "driver" of regionalization was a "for-profit corporation" — namely, PacifiCorp.

"I would encourage you not to hurry it up because that's what PacifiCorp wants you to do," he added.

Supporters Weigh In

The revised proposal also had its supporters.

"We do feel like this process [for creating the proposal] has been very transparent," said Jennifer Gardner, staff attorney for Western Resource Advocates, an environmental group. "We've been pleasantly surprised that recommendations were taken to change the second proposal."

Gardner called the regional market "the best opportunity to improve business as usual" in the West and said that any proposal taken to the legislature "should be as broad as possible to not tie the hands of the transitional committee." She said that GHG tracking on a regionwide basis would be important for assessing the environmental benefits of the market.

Jonathan Weisgall, vice president of legislative and regulatory affairs at PacifiCorp parent Berkshire Hathaway Energy, said CAISO's regionalization studies made it "very clear" that the region's 2030 GHG reduction goals "won't happen without a market."

In the "unlikely event" that regionalization did increase emissions from PacifiCorp's coal plants, the company would work to mitigate them, Weisgall said.

"In our Midwest utility [MidAmerican Energy], where we're moving to 80% renewables, we could not do that without a regional ISO," Weisgall said.

Preserving State Authority

Jan Strack, a transmission planning manager with San Diego Gas & Electric, said his utility has been in favor of expanding the market for a long time. He said the infrastructure for the market is already in place and that it wouldn't cost much money to expand it. Strack also contended that an expanded market would enable California to achieve its GHG goals at a lower cost.

"We need to avoid some roadblocks [in the governance plan]," Strack said. "The first one is preserving state authority.

"At the same time, we have to recognize that FERC has authority over interstate commerce," he added. "That's one area we would be uncomfortable handing over to the Western States Committee."

"We support regionalization of the ISO and the associated market because, frankly, they work," said Robin Smutny-Jones, director of California policy and regulations for Avangrid. "That's why there's been a proliferation of RTO-like structures across the country and around the world."

Smutny-Jones acknowledged the RTO would need to work through contentious issues such as transmission access charges and regional resource adequacy, both of which would be left to a newly constituted RTO.

"But other states have done it, and the West can too," she said.

CAISO NEWS

EIM Report Shows Continued Growth in CAISO Exports

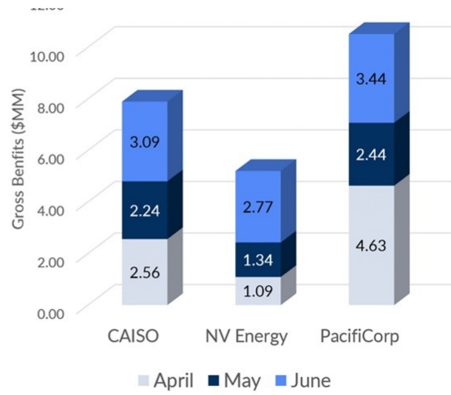
By Robert Mullin

The western Energy Imbalance Market continued to boost demand for California's surplus renewable generation last quarter, extending a trend observed during the first three months of 2016, according to CAISO's quarterly economic benefits report.

The eight-state EIM — comprising the CAISO, NV Energy and PacifiCorp balancing authority areas (BAAs) — absorbed 158,880 MWh of renewable supply that would have otherwise been curtailed, reducing carbon emissions by 67,970 metric tons through the displacement of thermal generation, the ISO estimates. Avoided curtailments increased by more than 40% compared with the first quarter.

The report showed that CAISO monthly exports into NV Energy increased by an average of 56% over the previous quarter. Much of that energy was wheeled into the PacifiCorp East (PACE) BAA, which has limited direct links with the ISO. Transfer capacity between the ISO and PACE increased from about 200 MW to 570 MW when NV Energy joined the EIM late last year.

While the report did not describe the specific reason for the uptick in transfers, PacifiCorp shut down four coal plants in April and May because of the EIM, according to Jonathan Weisgall, a vice president with Berkshire Hathaway Energy, PacifiCorp's parent company.



EIM benefits Q2 2016 *Source: CAISO*

"It is also worth noting that a significant level of energy exported by the ISO consisted of renewables," CAISO said, although the report did not break down exports by resource type. ISO exports peaked in May, when increased solar output typically coincides with mild weather and modest loads in California.

The EIM provided participants with $23.6 million in gross financial benefits during the second quarter, compared with $18.9 million the previous quarter, the report said. PacifiCorp realized the largest share of benefits at $10.5 million, followed by CAISO at $7.9 million. NV Energy's take increased threefold over the first quarter to $5.2 million.

Benefits can take the form of either cost savings — such as from reduced need for reserves or greenhouse gas credits — or increased profits from merchant operations. The benefits calculation nets out inter-BAA transfers that were scheduled ahead of the EIM's 15- and five-minute market runs to avoid attributing contracted flows to the market.

CAISO also estimated the EIM's effect on the procurement of flexible ramping capacity — resources equipped to respond to system variability stemming from the intermittency of renewable resources.

"Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA requirements," the ISO said, resulting in "flexible ramping diversity savings" stemming from a reduced procurement of flexible resources. It said the EIM produced a 26% reduction in the need for those resources during the quarter.

The EIM has accrued $88.2 million in benefits for its participants since it commenced operation in 2014, according to CAISO. Arizona Public Service and Puget Sound Energy are preparing to enter the market in October 2016, followed by Portland General Electric in October 2017 and Idaho Power in April 2018.

ERCOT NEWS

TAC News Roundup

Pricing Change on RMR Units Rejected, Appealed to ERCOT Board

AUSTIN, Texas — ERCOT's Technical Advisory Committee last week rejected a request to allow economic dispatch of reliability-must-run (RMR) units over the objections of the ISO's Independent Market Monitor and several of its Houston-area market participants.

NRG Texas drafted nodal protocol revision request 784, which addresses how RMR units are priced and dispatched, about the same time as ERCOT made its recent decision to extend into 2018 an RMR contract for NRG's Greens Bayou Unit 5 near Houston.

The contract requires ERCOT to pay $3,185/hour for the duration of the agreement and an incentive factor of as much as 10% to reserve the 371-MW gas-fired unit's capacity during summer months through June 2018. (See "Board Expands Greens Bayou RMR Contract to 2018," *ERCOT Board of Directors Briefs*.)

NRG's request would allow security constrained economic dispatch of RMR units to relieve transmission congestion after all other capacity available for transmission congestion relief had been exhausted.

Market Monitor Beth Garza supported the proposal, which she said would increase the dispatch price of RMR units, allowing other market units to be dispatched to resolve the constraint first.

In ERCOT's energy-only market, an RMR agreement results from either a poorly designed evaluation process — which mistakenly identifies a resource as needed — or a failure of the market to provide sufficient revenue to justify continued operation of a needed resource, she said.

"Should the failure be in the RMR designation process, the resource is unlikely to be deployed and its energy offer price will be immaterial," Garza said. "However, if the failure is in the market signal to units in this constrained area, the unit is likely to be deployed and the energy offer price will matter."

Bill Barnes, NRG Energy's director of regulatory affairs, said the request underscores the importance of sending the right price signals in the ERCOT market.

"We're spending $60 million on an RMR contract for the months of June, July, August and September," he said. "When you look at the State of the Market report for 2015, the real-time congestion rent for three of the major north-of-Houston constraints is $5 million. We're spending $60 million to solve a $5 million problem. There are legitimate situations where the market solves the problem in a cheaper way. The boogeyman that is high prices gets pummeled by the boogeyman that is RMR."

As drafted, NPRR784 would only apply when generator offers are mitigated because there is inadequate competition. RMR units are currently subject to the same offer mitigation as other units in such a situation, with Greens Bayou Unit 5 likely being offered at around $50-60/MWh. When there is adequate competition, RMR units are offered at $9,000/MWh under either the status quo or the NPRR.

The revision request would instead require all RMR units to be offered at the highest possible price that would still allow SCED to dispatch the unit for congestion. In Greens Bayou's case, the estimates are as high as $700/MWh.

The NPRR failed to gain the Protocol Revisions Subcommittee's endorsement during a roll-call vote July 14, but NRG appealed to the TAC. The revision request eventually fell short of the necessary two-thirds approval, with 54% positive votes and four abstentions.

NRG on Friday filed another appeal with the Board of Directors, which will consider the proposal at its Aug. 9 meeting.

"How do you prevent future RMR? By sending the right price signals," Barnes said. "The presence of the RMR is evidence the market signal has failed. 784 addresses the most important RMR issue: How do you send the right price signal? It's not a perfect solution, but is it better than what we have today? We believe the answer is yes."

Garza supported Barnes' position, although she also said she is a "huge believer" in ERCOT's stakeholder process and "what this room can do."

"Our position has been the objective of the RMR should be the price should be reflective of the unit not being there, but we should have the energy available to resolve the constraint," Garza said. "It is absolutely a shortage condition. If that situation did not exist, Greens Bayou would be on the way to the scrap heap right now.

"I'm sympathetic to the argument that, 'Gosh darn it, we spent $60 million on this unit, why can't we use it?'" Garza said. "However, believe it or not, those are sunk costs … that don't change if you resolve this situation. When you're talking about resources necessary to resolve a transmission constraint, there are two factors: the offer price or mitigated offer cap, and the shift factor of the unit on that constraint — the effectiveness of that unit to relieve the constraint."

"We generally agree with the IMM … but we disagree that 784 as a one-off is the solution," said Energy Future Holdings' Amanda Frazier, chair of the PRS. "We're concerned [NPRR784] is reactionary. It doesn't address whether Houston prices are high enough to allow RMR. If we pass this, we're paying for incorrect price signals."

Katie Coleman, with the Texas Industrial Energy Consumers group, represented the PRS position, arguing NRG's proposal is punitive to loads, encourages unit retirements by providing scarcity pricing in non-scarcity conditions and prevents the RMR unit from solving other constraints beyond a single transmission line.

"We have concerns about requiring loads to also pay $600-800/MWh to use that unit for the very purpose it was placed under an RMR contract," she said. "We have concerns about the incentive this creates for a generating company with a fleet of units in a certain area to retire units and get high pricing for its other units. [NPRR784] would require Greens Bayou to be priced at the highest possible price to solve, which would preclude it from solving other constraints in area."

Noting that the revision request has been classified as urgent, Coleman said that electric retailers are concerned its requested September implementation timeline does not provide enough lead time for Greens Bayou and other generators in the area.

Coleman also noted customers are paying for Greens Bayou only until the Houston Import Project goes into service as early as 2018, when it is expected to solve the region's congestion issues.

"This NPRR is sending a price signal too late to matter," Citigroup Energy's Eric Goff said. "The fact the contract exists is interfering

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ERCOT NEWS

TAC News Roundup

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with what would happen had the unit been allowed to retire. It gets to the point of whether there's a weird incentive here."

"If you're a load outside of Houston, I have no idea why you're not outraged," Barnes said. "If the load in Houston has a small load-ratio share, I can understand why you would want someone else to solve your problem. We're an energy-only market. Price signal is everything."

Shortly after the TAC meeting concluded Thursday, ERCOT posted answers to questions it received from its request for proposals for must-run alternatives to the Greens Bayou RMR contract. (See *ERCOT Seeks Alternatives to Houston-Area RMR Unit*.)

Committee Discusses July 7 System Outage

ERCOT staff shared its analysis of the July 7 outage of its Energy Management System. The outage lasted 102 minutes and resulted in corrupted data being passed to down-stream systems, including settlements and reports. Market participants said they saw a perceived drop-off in load and generation, but their primary complaints were around a lack of information coming from the ISO.

"When these things are occurring, I know ERCOT is scrambling to recover and get the grid stable again," Barnes said. "From a market perspective, it was pure chaos. Market notices should be crystal clear about what is happening."

"We just knew something was wrong because of operation notices," Goff said. "Knowing the extent of the outage would be beneficial to the market."

"We want to share with you the information we definitively know as quickly as possible," said Kenan Ögelman, ERCOT's vice president of commercial operations. "The tension we're trying to balance is how long to hold information back until we can be sure" it's accurate information.

The problem began at 11:41 a.m., when an operator mistakenly loaded test data into the active system, which corrupted data in the emergency system's network model. Between 11:59 a.m. and 12:16 p.m., the market's qualified scheduling entities were instructed to assume constant frequency control. By 1:23 p.m., the data had been corrected and verified, and operations returned to normal.

Corrected prices were posted for the affected SCED intervals, and staff said that it is continuing to evaluate alternatives that may affect subsequent settlements.

Price-Correction NPRR Approved

Barnes was successful with a second NPRR, dealing with ERCOT's price-correction process following a SCED failure. NPRR696, which Barnes drafted on behalf of NRG subsidiary Reliant Energy Retail Services, passed with 72% of the vote.

"When the SCED system is not running, inputs grow stale. When it starts back up, things don't make sense," Barnes said. "It comes down to whether you believe the last best price, or whatever it spits out."

NPRR696 establishes a price-correction policy that uses the last good price for settlement until ERCOT no longer requires manual action to stabilize the system. Barnes said that correcting prices for settlement intervals corresponding to the active watch period would give market participants transparency to known prices that reflect the last good SCED execution.

"This policy would extend that last good price for another 15 minutes," Barnes said. "It could be the last high price or the last low price."

The TAC unanimously endorsed six other NPRRs, a system-change request (SCR) and revisions to the Nodal Operating Guide (NOGRR), the Planning Guide (PGRR), the Retail Market Guide (RMGRR) and the Resource Registration Glossary (RRGRR).

- NPRR738: Excludes from performance calculations intervals when an emergency response service generator is unable to meet its obligations because of transmission/distribution service provider (TDSP) outages.
- NPRR747: Proposes new definitions related to voltage profiles, defines various entities' responsibilities related to voltage support and clarifies that the interconnecting transmission service provider or its designated agent may modify a generation resource's voltage set point.
- NPRR767: Changes the eligibility check for the startup portion of the reliability unit commitment make-whole payment. Resources with lead times longer than six hours may submit a settlement dispute to have their resource-specific startup times considered when determining eligibility for startup costs included in the make-whole payment calculation.
- NPRR770: Adds visibility and situational awareness to the market by posting the aggregate number of telemetered resources and their statuses to the ancillary service capacity monitor.
- NPRR771: Clarifies that TDSPs must ensure an electric service identifier has been created in ERCOT systems before initiating electric service at a premises, avoiding related transactional, billing and out-of-sync issues.
- NPRR774: Removes duplicate language regarding the calculation of seasonal transmission-loss factors.
- NOGRR155: Clarifies voltage ride-through performance requirements for all generation resources immediately following a fault, stipulating that they must remain online and connected to the transmission system, and also maintain real power.
- PGRR046: Aligns the planning guides with NERC's TPL-007-1 reliability standard related to geomagnetic disturbances by specifying a process for developing geomagnetically induced system models.
- RMGRR138: Removes the requirement for retail electric providers serving pre-pay customers to provide a weekly list of electric service identifiers to Oncor, replacing it with the requirement to provide the prepay list upon Oncor's request.
- RRGRR009: Adds three categories of data: voltage limits for resources' substation transmission level equipment; geomagnetically induced currents and the presence of blocking devices to allow for the study of any vulnerability attributed to geomagnetic disturbances; and a most limiting single element (MLSE) allowing a resource entity to identify an MLSE on lines it doesn't own.
- SCR789: Updates the Network Model Management System topology processor to add a software tool commonly used by transmission-planning entities in ERCOT.

— Tom Kleckner

MISO News

Informational Forum Briefs

June Energy Prices Up Across Footprint; New Emergency Pricing Encounters Snag in July

CARMEL, Ind. — Increased natural gas prices and congestion in MISO South boosted energy prices 23% in June, according to the RTO. Day-ahead energy prices in June averaged $27.36/MWh; the real-time average price followed closely at $27.42/MWh.

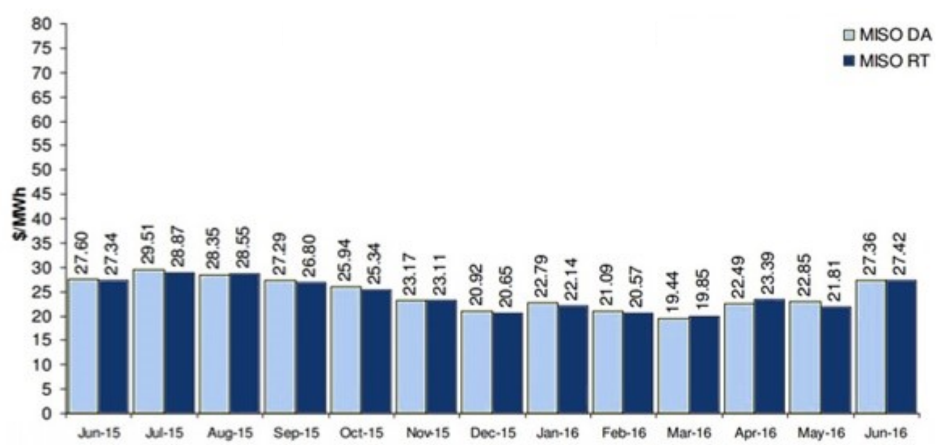
MISO also reported that above normal temperatures in June drove the average load to 83.1 GW, a 3.5% increase in a year-over-year comparison. Load peaked at 112.5 GW on June 20.

“We did see above normal temperatures generally throughout the region, throughout most of the month, and we did issue several hot weather alerts in different parts of the footprint on various days,” Vice President of System Operations Todd Ramey said during a July 26 Informational Forum.

Ramey also said MISO tested its new emergency pricing structure on July 21 during a three-hour maximum generation event. Ramey said a Detroit-area thunderstorm and market participants self-deploying emergency resources upon the event declaration reduced peak load by “a couple thousand megawatts,” which resulted in “plenty of supply cushion as [MISO] moved across the peak that day.” MISO’s peak on the day was 121,000 MW, below the forecasted 126,000 MW.

A review by MISO’s pricing team of the emergency event uncovered a software logic error that required a fix from the vendor, Ramey said. MISO will review the event and post recalculated real-time prices for July 21 before the Aug. 2 Market Subcommittee meeting, at which RTO officials will explain the issue and the correction, he said. The RTO rolled out the new emergency pricing structure on July 1. (See “MISO to Set Two Emergency Pricing Offer Floors,” *MISO Market Subcommittee Briefs*.)

Ramey also said MISO plans to present its response to the eight new recommendations in the Independent Market Monitor’s State of the Market report at the September meeting of the Markets Committee of the Board of Directors. (See *Monitor’s State of the Market Report Seeks Changes to MISO ELMP*.) In the meantime, he said, the RTO is working with Monitor David Patton “to make sure we understand all of the new recommendations.”



MISO systemwide day-ahead and real-time LMPs. Note: based on the monthly hourly of the active hubs. *Source: MISO*

MISO Asks Members to Consider Bylaw Changes

MISO is considering reducing or eliminating the service prohibition on members of its Board of Directors in revisions to its Transmission Owners Agreement and Bylaws.

Deputy General Counsel Eric Stephens said the RTO is considering “less onerous” restrictions on the directors, who currently have two-year pre- and post-service prohibitions from utility and wholesale energy market participants. Stephens said the rule could be eliminated or reduced to either one-year pre- and post-service prohibitions or a one-year pre-service prohibition and no post-service prohibition.

Easing the restrictions would improve director recruiting and be more consistent with other RTOs, Stephens said. Seats currently occupied by Chair Judy Walsh and members J. Michael Evans and Paul Feldman are up for election this year.

Other bylaw revisions could mean that MISO would no longer be required to hold its annual meeting on the second Thursday of December. The RTO also is considering holding board elections — currently held at the annual meeting — earlier to ensure consistency with the new board meeting schedule. The slate would be announced in September, with results announced as early as the Oct. 25 Informational Forum.

Another revision would clarify that a majority of the directors constitutes a quorum for calling a meeting or tallying a vote.

Stephens said MISO also is seeking to change the invoicing of the $1,000 annual membership fee from the current Jan. 1 to dates tied to the time of year each member joined.

The bylaw changes were suggested by MISO’s Corporate Governance and Strategic Planning Committee. Stephens said none of the revisions would impact transmission owner rights or obligations.

MISO is seeking stakeholder feedback on the proposed changes by Aug. 15. If stakeholders are in accord, the RTO could file revisions by the fourth quarter.

EPA Official Makes Case for CPP

Janet McCabe, EPA’s acting assistant administrator for the Office of Air and Radiation, made a case for the Clean Power Plan, saying MISO’s comments to the agency were “incredibly constructive.”

She also expressed confidence that the rule will survive legal challenges. Oral arguments on the challenge are scheduled before the D.C. Circuit Court of Appeals for Sept. 27.

EPA is accepting comments until Sept. 2 on its Clean Energy Incentive Program (CEIP), an optional early-action program that would help states meet their CPP emission targets through incentives for investment in

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MISO NEWS

MISO, PJM Unveil JOA Process for ‘Targeted’ Market Efficiency Projects

By Amanda Durish Cook

MISO and PJM are seeking to hammer out new joint operating agreement language that would allow accelerated approval of short-term projects intended to relieve congestion at the RTOs’ seams before advancing further on a joint study that would identify potential projects.

MISO engineer Adam Solomon said that while the RTOs continue to work on the language detailing joint targeted market efficiency projects (TMEPs), the JOA needs to have a vetted process in place before project selection begins.

“We should really have the JOA language worked out before we push further into the study,” PJM engineer Alex Worcester agreed during a July 29 meeting of the MISO-PJM Interregional Planning Stakeholder Advisory Committee (IPSAC).

Targeted MEPs will differ from ordinary MEPs, which undergo a “longer and more rigorous” review that combines regional approval, modeling and analysis, and a review timeline. MEP rules may also be changing as a result of a FERC order requiring the RTOs to revise their interregional approval processes. (See *MISO, PJM Working to Comply with NIPSCO Order*.)

The two RTOs are currently evaluating 13 potential small projects in Illinois, Indiana, Michigan and Ohio.

“We’re really looking for the small, low-cost, short lead time projects that alleviate historical congestion at the seam,” Worcester said.

“We’re reviewing the upgrades and we’re working to ensure they’re effective and alleviate congestion,” Solomon said.

Officials from both RTOs said construction of the small projects could begin before the end of the year. That would require a special approval process developed within “a very tight timeline,” said Worcester, adding that the JOA should set out a simple method for TMEP approval.

The JOA stipulates that TMEPs must be in service within three years and cost less than $20 million. Projects exceeding the cap would move to the MEP classification. Because of the near-term nature of TMEPs, inflation rates will not be factored into the cost-benefit calculation.

MISO and PJM also propose to replace the current 1:1 cost-benefit ratio with a requirement that TMEPs produce enough benefits to cover their costs within four years.

“It’s a pretty high hurdle for these projects to pass,” Worcester said. “It’s consistent with our goal of having high-impact projects.”

To determine if a project meets the cost-benefit metric, the RTOs will rely on three years of historical congestion data to project a future case adjusted by market-to-market payments.

The new cost-benefit approach will “avoid complicated analysis,” said Worcester, who added that he could further illustrate the approach at the Aug. 26 IPSAC meeting.

The RTOs also want to be able to discount historical congestion at flowgates — used to determine TMEP project eligibility — by factoring in congestion hedges or auction revenue rights.

Worcester said that flowgates have an average of 30 to 40% of their flow hedged, but some flowgates have 100% hedging while others have zero. “What we’ve seen is a lot of variability from flowgate to flowgate,” he said.

Stakeholders are asked to provide feedback on the proposed TMEP language by Aug. 12. Final draft language will be presented at the Aug. 26 meeting.

“We’re making good progress toward getting this filed,” Worcester said.

Informational Forum Briefs

Continued from page 8

demand-side energy efficiency and solar power generation in low-income communities. The program also encourages early investment in non-emitting wind, solar, geothermal and hydropower generation.

MISO Executive Director of External Affairs Kari Bennett said MISO and PJM plan to conduct a joint impact study on the CPP during the second half of this year. MISO stakeholders have asked for a similar study with SPP.

ARPA-E Program Director: Research Collaboration Discussion to Take Place at Symposium

Tim Heidel, program director of the Department of Energy’s Advanced Research Projects Agency-Energy (ARPA-E), previewed MISO’s Aug. 18-19 Market Symposium, which will focus on technology partnerships among researchers, startups and RTO stakeholders. Heidel will be a panelist at the session in Indianapolis. (See *Energy Department’s ARPA-E to Join MISO for First-Ever Market Symposium*.)

— Amanda Durish Cook

NYISO News

New York ESCO Order Vacated by Court

By William Opalka

> **"The court is perplexed that implementation [of the order] would be so immediate, when by the PSC's own admission so many questions remain."**
>
> **New York Supreme Court Justice Henry Zwack**

A New York judge has vacated the Public Service Commission's February "reset order" that sought to overhaul the business practices of retail energy suppliers.

The July 22 order by acting state Supreme Court Justice Henry Zwack said energy service companies (ESCOs) were denied due process by the commission, especially by the strict time frame for compliance (870-16, *et al.*).

The order bars the PSC from enforcing a requirement that ESCOs guarantee retail and small commercial customers will pay no more than they would for default service (excluding contracts offering at least 30% renewable power) (15-M-0127, *et al.*).

It also throws out a requirement that ESCOs receive "affirmative consent" from such customers before renewing them from a fixed rate or guaranteed savings contract into one that provides renewable energy but does not guarantee savings.

Zwack left standing language the commission added to its business practices imposing tougher enforcement measures against those who prey on vulnerable or uninformed customers.

While regulators insisted they acted to protect customers from deceptive business practices, ESCOs said the order effectively killed customer choice in New York.

The order "is arbitrary and irrational in that it imposes the unexplained and harsh 10-day implementation period for the order, which amounts to a major restructuring of the retail energy market — or even its collapse," Zwack wrote in his 26-page opinion. "The court is perplexed that implementation would be so immediate, when by the PSC's own admission so many questions remain."

PSC officials said they will address the judge's procedural concerns promptly.

The commission acted in response to what it said was unscrupulous business practices by some retailers. ESCOs immediately challenged the order in court and also sought a rehearing by the PSC. (See *Retailers Ask for Rehearing of NY Guaranteed Savings Order*.) A stay was granted in March as the court challenge was pending.

Retail Energy Supply Association spokesman Bryan Lee said the group was "gratified that the court vacated the … order, finding the PSC action to be 'irrational, arbitrary and capricious' and failed to offer ESCOs 'an opportunity to be heard in a meaningful manner and at a meaningful time.' The court found that ESCOs were 'stripped of any meaningful opportunity to participate in the promulgation of the reset order.'"

Zwack reaffirmed that the PSC maintains jurisdiction over retail rates, turning aside a challenge from the ESCOs.

"The court's affirmation that the PSC has legal jurisdiction over ESCOs is an important win for the PSC and millions of consumers in New York," PSC spokesman James Denn said in a statement. "The procedural flaws highlighted by the court have been addressed, or will be, as we continue to move forward with Gov. [Andrew] Cuomo's far-reaching plan to protect customers from unscrupulous ESCOs. Make no mistake, we are putting an end to deceptive ESCO practices that harm electric and gas customers."

Zwack's ruling does not affect a PSC order earlier this month imposing a moratorium on ESCOs signing up additional low-income customers. Regulators issued the order after a collaborative effort failed to develop a formula under which customers could be guaranteed savings. (See *NYPSC Declares Moratorium on Low-Income Sign-ups*.)

In a statement released Tuesday, PSC Chair Audrey Zibelman defended the commission's actions.

"When ESCOs were charging multiple times the prices that utilities charge for energy, and consumer complaints of deceptive marketing practices poured in by the hundreds, the commission took bold action in February to protect consumers," she said. "Unfortunately, as a result of the litigation, ESCO customers are still paying millions of dollars more every month than they should be paying for electric and gas services. But this injustice will be short-lived. … The commission will easily address the procedural concerns raised by the court and will continue our work to ensure that all electric and gas consumers in New York have the protections they need and deserve."

NYISO NEWS

New York Adopts Clean Energy Standard, Nuclear Subsidy

Continued from page 1

be produced at scale.

"If these plants close abruptly, they in all likelihood will be replaced by the attributes of expanded fossil fuel base generation," PSC Chair Audrey Zibelman said at the meeting. "This will impair our ability to achieve our environmental goals."

Zibelman

Zibelman also disputed the estimates of the plan's price tag, saying that opponents of nuclear subsidies are presupposing that record-low natural prices will continue, highlighting the differential from the relatively higher prices for nuclear. "By not effectively pricing in the cost to our environment of our electric choices, we are, in fact, causing economic inefficiencies," she said.

An overflow crowd of union members, environmentalists and pro- and anti-nuclear activists filled the PSC meeting room, necessitating the use of four supplemental hearing rooms for videoconferencing.

"We're very supportive of every effort to support renewable energy," Jessica Azulay, of the Syracuse-based Alliance for a Green Economy, said after the meeting. "But we're very disappointed by the decision to subsidize nuclear power and prevent the closure of nuclear reactors."

"We have a new power market here, and that's going to reflect the societal price of

Azulay

Wilcox

carbon, so we can't really call this an above-market contract," Phil Wilcox, representing the International Brotherhood of Electrical Workers Local 97, based in Buffalo, said after the meeting.

PSC staff recently revised its calculation for ZECs to base their value on EPA's social cost of carbon instead of a previous proposal to value them on the difference between the cost of service for nuclear plants minus wholesale power prices in the NYISO market. (See Commenters Laud, Blast New York's Nuclear Subsidy Plan.)

The ZECs will be worth $17.48/MWh for the first two years of the program, or about $965 million. The order mandates that electric distribution companies purchase ZECs representing a proportion of their annual load, based on annual forecasts.

The state-owned New York Power Authority and the Long Island Power Authority are exempt under state law, but Zibelman said that officials at both entities indicated that they will voluntarily comply with the CES, including the ZEC payments.

The plan has been favored by legislators in western New York, where the plants are located, labor unions, economic development proponents and some environmentalists.

NYPSC commissioners Diane Burman, Chair Audrey Zibelman and Gregg Sayre © *RTO Insider*

"Today's implementation of the CES is a momentous day for the state of New York, and more specifically, the upstate communities that have waited anxiously for months for this moment," the Upstate Energy Jobs Coalition said in a statement.

The subsidy was opposed by other environmentalists, large commercial and industrial customers, power generators and marketers, and elected officials from other parts of the state. Some environmentalists dispute the clean energy attributes of nuclear. Customers objected to the plan's cost, and generators and marketers said the plan interfered with the competitive power market.

The plan opens the door for Exelon to become the sole owner of the four plants on Lake Ontario — R.E. Ginna, Nine Mile Point Units 1 and 2 and James A. FitzPatrick, which it is seeking to acquire from Entergy. (See Entergy in Talks to Sell FitzPatrick to Exelon.)

Entergy previously said it would close FitzPatrick early next year. Exelon said it would close Ginna and Nine Mile Point 1 in March if it did not have a contract with New York by the end of September. (See Exelon Threatens to Close Nine Mile Point 1.)

"This is one of the largest corporate bailouts in New York's history and it will benefit only one company, Exelon Corp.," a coalition of elected officials and environmental organizations argued last week.

The other nuclear power plants in New York, Entergy's Indian Point Units 2 and 3, are currently ineligible for the subsidies under the plan adopted Monday. However, under the staff's revised proposal, Indian Point could become eligible for ZECs in the future if it could prove it was financially stressed. Gov. Andrew Cuomo has advocated the closure of Indian Point because of its proximity to New York City.

Zibelman said Indian Point was not excluded from possible eligibility so that the order would be "non-discriminatory."

Exelon began a separate proceeding in the spring to seek cost-of-service-based compensation for its plants in the event that the PSC did not act in time to address its request to keep the nuclear plants viable. That proceeding was rolled into the larger CES case by the commission.

Infocast 2nd NY Energy REVolution Summit

'Transformative' Still the Apt Description for New York REV

By William Opalka

NEW YORK — Speakers at Infocast's 2nd NY Energy REVolution Summit last week pondered how New York's Reforming the Energy Vision could deliver on its promise of cleaner and more distributed generation, with persistent low power prices.

The challenge is introducing transformative changes in an environment of already record-low prices, changes that would reduce margins for market participants while also requiring massive investments.

"The state of New York has embarked on two significant transformative issues simultaneously: the Clean Energy Standard driving toward 50% renewables [by 2030] and REV," **Michael Schwartz**, CEO of advisory firm New Wave Energy Capital Partners, said during a panel discussion on the latest developments of REV. "If I have seen in the past the potential for stranded investment, this is it. If we're going to achieve the CES, the state is going to [need to] create incentives for market signals to drive the construction of utility-scale renewables at the same time we're driving down demand and moving [generation] behind the meter."

Schwartz said regulators will somehow need to reconcile the initiatives.

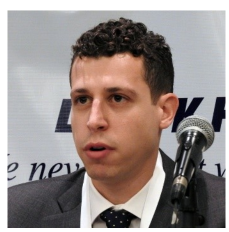
"The fundamental change to move from cost-of-service to market-based [utility earnings] is conflicted with maintaining the financial integrity of electric utilities," he said.

Utilities, while understanding the imperative to revamp their generation fleets, maintain infrastructure and preserve their financial viability, are wary, he added.

"Based on discussions I've had, the consensus in other jurisdictions is 'we're not doing that,'" Schwartz said.

New York is moving ahead on another legally uncertain path to create financial incentives for its struggling nuclear fleet until large-scale renewables are built to take their place. On Monday, the New York Public Service Commission approved a zero-emission credit for nuclear plants, at a projected cost of $7.6 billion over 12 years. (See related story, *New York Adopts Clean Energy Standard, Nuclear Subsidy*, p.1.)

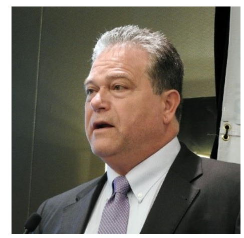
A proposal earlier this year based the ZEC subsidy on the difference between the cost-of-service from the nuclear plants and the wholesale power prices in NYISO. A PSC staff proposal in July changed the formula to align with EPA's calculation of the social cost of carbon. Generation owners, customers and some environmentalists object.



David Appelbaum, an attorney for the New York Power Authority, said the change was the result of the U.S. Supreme Court's April decision in *Hughes v. Talen*, in which the court voided Maryland's attempt to incent generation by using a contract for differences related to the PJM capacity market. (See *Supreme Court Rejects MD Subsidy for CPV Plant*.)

"The order has changed significantly. Before the change, it would have been open to challenge in the context of the [*Hughes*] decision," Appelbaum said. "It's less so, but there's still risk."

Whatever the eventual outcome, New York has gotten ahead of many places as it embarks on REV.



"Once you start looking at the regulatory paradigm, regulation was not intended to support this vision. Regulation is still cost-of-service-based," said **Paul DeCotis**, a senior director at West Monroe Partners and panel moderator.

However, **Jim Gallagher**, executive director of the New York State Smart Grid Consortium, said the model is still relevant for now.

"We need to remember that utility cost-of-service regulation is still going to provide 96% of utility revenues for the foreseeable future and these initiatives are going to provide less than 4%," he concluded.

The New York State Energy Research and Development Authority is now the lead agency backing a proposed 90-MW offshore wind development south of Long Island. "Offshore wind is clearly a critical part to achieving Gov. [Andrew] Cuomo's clean energy agenda of achieving 50% by 2030. The numbers offshore are huge, with us talking about 38 GW of potential near the downstate load centers," NYSERDA CEO **John Rhodes** said.

Infocast 2nd NY Energy REVolution Summit

Jamie Resor, CEO of solar project developer groSolar, said his peers need certainty, and a commitment from policymakers could be more valuable than a better credit rating for a project in a state where the likelihood of a failed deal may be higher. “New York surely is not the least expensive place to do business, and it certainly is not the sunniest ... but you’re in a state that has big goals, and we have a [committed] partner, and while we’re not certain how we’re going to [reach those goals], we know that somehow we’re going to figure it out,” he said.

Craig Lewis is executive director of the Clean Coalition, a nonprofit promoting a modernized grid to hasten the integration of renewable energy. He said failing to understand the way distributed wind, solar or storage add value to the system — in providing reactive power or resiliency to benefit system performance, for example — creates challenges.

“If you don’t understand how these resources are going to work together, there’s no possible way you can optimize them from a policymaker’s standpoint. You cannot go forward and design a market mechanism” that incentivizes participation, he added.

Mike DeSocio, senior manager of market design at NYISO, said the ISO is working on a distributed energy resources roadmap in order to determine how they affect the wholesale market.

“The questions we are trying to answer are: How do these resources interact with the ISO? What services can these resources provide, and what kind of configurations and uses are we thinking about to utilize these resources? ... It’s going to be a little bit of a journey, so the way the ISO is thinking about this is in small stages of three to five years. We’re not trying to project out 20 years.”

Doug McMahon, vice president of strategy for the New York Power Authority, said the Reforming the Energy Vision promise of customer-centric engagement between energy consumers and utilities has been slow to develop.

“We’re in for an interesting year, when we’ll have a clearer understanding if there are going to be long-term successes with REV,” McMahon said. “There is increasing frustration in the amount of progress that’s being made. The substance of REV is development of market forces, and at the moment, those forces aren’t strong enough to animate the consumer or the utility into integrated action. Until we see those forces become stronger, we’re not going to see a great deal of momentum.”

PJM NEWS

PJM Members Spar over Capacity Performance Penalty Rate

By Suzanne Herel

WILMINGTON, Del. — PJM stakeholders rejected a pair of dueling measures Thursday, leaving a new senior task force to decide whether to reconsider a formula key to calculating nonperformance penalties under the new Capacity Performance rules.

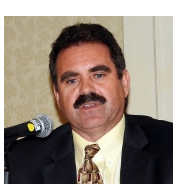
The sector-weighted votes capped more than an hour of heated discussion at the Markets and Reliability Committee that included allegations of political maneuvering and a call for one member to be sanctioned for "*ad hominem* attacks."

The debate was sparked by the proposed charter of the Underperformance Risk Management Senior Task Force (URMSTF), an item that had been approved by lower committees with little to no discussion, despite months of controversy over the problem statement that created the group. (See *PJM Generator Risk Proposal Faces Resistance*.)

In recent task force meetings, however, some members had raised the question of whether the RTO was using an unrealistic number in figuring its performance assessment hour (PAH) charge rate. They worried it would artificially lower penalties in the new regime, under which generators are eligible for bonus payments and exposed to financial penalties depending on their performance. Lowering the penalties, some members argued, would weaken generators' incentive to perform under the new market model.

Thus ensued speculation over whether such a discussion fell within the task force's scope.

Calpine Offers Problem Statement


Scarp

Fearing that the issue might be determined to be beyond the group's mandate, David "Scarp" Scarpignato of Calpine brought a problem statement to the MRC to ensure the formula would be discussed somewhere.

"PJM had suggested that maybe it could be covered under the" task force, Scarp said. "I had indicated that I wasn't sure that was the group to cover it because they seem intent on reducing the incentives for performance."

According to the problem statement, informed by data from the Independent Market Monitor, "The current PAH number used in the denominator of the nonperformance charge rate does not reflect the expected number of PAHs as intended. The use of 30 hours is not adequately supported. The average of the RTO-wide PAH in the last three years was 14 hours, including the 30 hours in delivery year 2013-2014 that resulted primarily from January 2014, an outlier year.

"Too low of an expected PAH value avoids confronting capacity resources with the intended nonperformance disincentives under CP philosophy."

The penalty nonperformance charge rate is the net cost of new entry ($/MW-day) multiplied by 365 days and divided by the 30-hour PAH value. Thus, if the value were reduced from 30 hours to 14, the penalties would more than double.

Scarp said that he had raised this issue at the last task force meeting.

"People talked at least five minutes about what's in the scope and out of scope with this charter. There were varying opinions. People for the most part wanted to go past managing the risk and talk about the penalties you'd be exposed to. … If the group is looking at risk, it can't be only one side, to make CP weaker."

If the task force is limited to hedging risk, he said, its charter might as well be called the "reduce the CP effectiveness proposal."

Incentives Key to CP

Dan Griffiths, executive director of the Consumer Advocates of PJM States, said it was important to guard performance incentives.

"If the incentives are, in fact, less, we feel like we are losing ground here," he said. "That's the only thing [consumers] got out of this — it's in the interest of consumers to have strong incentives.

"You can't quintuple the actual rate, but there is a discussion to be had here."

Mitigating Risk for Generators

On the other side of the debate was Bob O'Connell on behalf of PPGI Fund A/B Development, who authored the problem statement that begat the task force. PPGI is the parent company of Mattawoman Energy, which is building a combined cycle plant near Brandywine, Md., in Prince George's County.

O'Connell introduced the initiative in October, saying CP allows companies with multiple generators to offset poor performance with over-performing units but does not allow after-the-fact offsets, such as bilateral trades, that could help smaller generators. (See *Generators Seek to Reopen PJM Capacity Performance Rules*.)

At Thursday's meeting, he proposed a motion to put off reassessing the PAH charge rate formula until after PJM has submitted an annual informational filing mandated by FERC in approving the charge rate. It was seconded by Jason Cox of Dynegy.

Countered Scarp: "Putting this off into limbo is a terrible thing to do to a fellow stakeholder, and something I have never done." He accused O'Connell of using "procedural moves to prevent voting on this order" and being "disingenuous," which elicited a call from O'Connell to have him sanctioned for "*ad hominem* attacks." Committee Chair Suzanne Daugherty did not formally act on his request.

Breaking a Rule of Thumb

Indeed, most members prefaced their comments by saying as a rule of thumb, they do not oppose problem statements. It's highly unusual for them to be rejected.

But after O'Connell's measure failed with slightly less than 49% approval, members also voted down the Calpine problem statement, which was endorsed by slightly more than 44% of the votes.

Members subsequently approved the task force charter by acclimation.

The votes cut across sector lines, with generators split on the issue but more favoring O'Connell's motion. The only sector to unanimously support Calpine's

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PJM NEWS

PJM Members Spar over Capacity Performance Penalty Rate

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initiative was the End-Use Customers (albeit with one abstention).

Jason Barker of Exelon had provided the "second" needed for a vote on the problem statement.

"The data shows quite strongly that 30 hours … is vastly overstated," Barker said.

He joined Scarp in criticizing his colleagues for "procedural shenanigans and weak arguments" and encouraged them to put aside politics, saying that no one got everything they wanted out of the CP construct. "Let's be honest around the table," he said.

FERC Has Spoken

Some members said they were hesitant to revisit the issue because FERC had approved the charge rate using the 30 PAH hours.

Although the commission approved the 30-hour proposal as a "reasonable approximation of the upper bound" of hours during which PJM is likely to experience emergency actions, it also required the RTO to submit informational filings for five years evaluating the impact of the 30-hour assumption on resource performance. "We also encourage PJM, as it gains more experience under its new capacity construct, to reassess the assumed number of performance assessment hours and file with the commission if it believes a revision is warranted," the commission said.

Scarp noted that FERC's order hasn't stopped stakeholders from questioning other aspects of the ruling, including operating parameters and seasonal capacity. The 30 hours, he said, is an error.

Carl Johnson, of the PJM Public Power Coalition, said, "We do not like to oppose a problem statement — that's how we got to move forward with the URMSTF and seasonal capacity. But in this particular case, we're talking about something so specific that FERC gave us a directive on."

He referenced PJM's recent experience spending months hammering out consensus on a ramp rate for the CP product, only to have FERC reject it.

"I'm not inclined to use our time on this," he said. "I don't want to spend time taking things to them that aren't going to go anywhere."

Susan Bruce, of the Industrial Customer Coalition, agreed that the charge rate was a core issue of CP, but she said it was just one and hesitated to approve re-evaluating it without looking at others.

"If you say we can't talk about those other components, I think it's a conversation to be had in a vacuum," she said.

Scarp responded, "If you think that there are other numbers that are incorrect, I'm happy to look at them. I am not redesigning CP in any way. I'm probably one of the few people in the room who has never tried to redesign CP."

PJM NEWS

MRC/MC Briefs

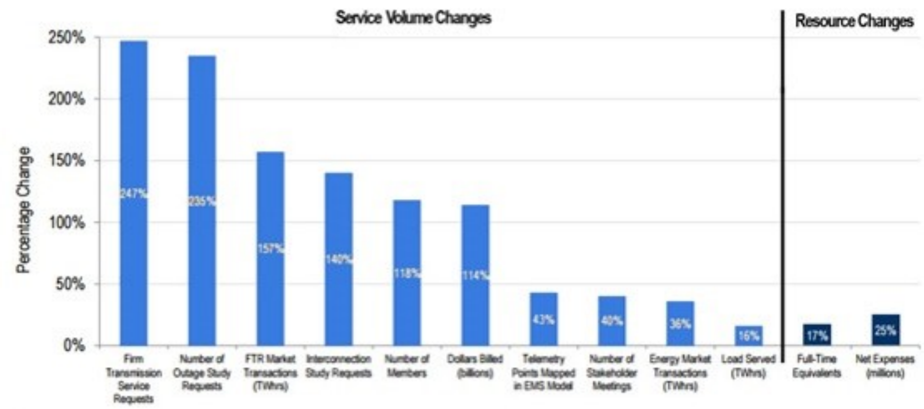
PJM Eyes Fee Hike

WILMINGTON, Del. — PJM needs to increase its fees to cover rising expenses and rebuild its diminishing operating reserve, officials told the Members Committee on Thursday.

Staff presented a first reading on five options for revising the administrative rate used to collect fees from members and market participants.

PJM is looking for member approval to increase the rates to $0.41/MWh of load served, up from the $0.37/MWh for 2017. The options presented include a single change to a $0.41 rate, a 2.5% annual increase starting in 2018 through 2023 or an annual $0.01 increase through 2022.

A new method is necessary because PJM has been below its authorized operating reserve of $15 million since 2013. Staff had expected to rebuild the reserve to $17 million in 2015. Instead, it saw the reserve fall to $7 million because of lower-than-expected revenues. Although it trimmed expenses by $10 million below budget, to $273 million, it generated revenues of only $269 million.



2006-2015 service volume/resource changes *Source: PJM*

PJM has changed the way it charges members and market participants several times over the past 20 years.

Before 1999, the RTO charged members a single formula rate based on load served. From then until May 2006, the RTO moved to multiple formula rates based on both load and market activity.

In 2006, PJM added a rider to cover the cost of the Advanced Control Center (AC2), and in 2011 it decreased service category rates by 3%, citing economies of scale. All proposals assume an early retirement of this rider because the debt attached to it will be paid off in September

The Finance Committee is expected to make a recommendation to the Members Committee and Board of Managers at its meeting Aug. 24.

CFO Suzanne Daugherty said she expected the committee to choose an option calling for a 2.5% annual increase from 2018 through 2023, which would restore the reserve to full funding by the end of 2017 and maintain it through 2026.

PJM will return to the Members Committee in September for an endorsement vote. It will then make a filing with FERC with a target effective date of Jan. 1.

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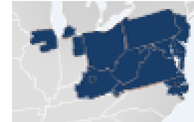
PJM NEWS



MRC/MC Briefs

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Grid Remains Strong During Recent Heat Wave

PJM canceled maintenance outages for the first time under Capacity Performance rules as the system experienced seven days of hot weather beginning July 21, Mike Bryson, vice president of operations, told the Markets and Reliability Committee on Thursday.

The peak load for the period — 151,882 MW — occurred July 25. That was the RTO's 13th-highest ever and the highest since July 2011, when PJM set an all-time record of 165,492 MW.

The daily average LMP for July 25 was almost $36/MWh, Bryson said. Forced outages for the period were less than 13,000 MW.

"The transmission system has been very strong on the voltage side," he said. During the period, however, two 765/345-kV transformers tripped in different parts of the system, causing local congestion.

The Dumont T2 line in Indiana tripped July 21, and the Cloverdale-Joshua Falls line in Virginia tripped July 26 because of storms, Bryson said.

PJM Moves Toward Order 825 Compliance Filing

The MRC approved a problem statement to begin work on compliance with FERC Order 825, which set new rules for RTO settlement intervals and shortage pricing triggers. Staff will begin work at the Aug. 10 Market Implementation Committee meeting to identify and address potential impacts. (See "Members Prepped for Problem Statement on Settlement Intervals, Shortage Pricing," *PJM Markets and Reliability and Members Committees Briefs*.)

The order requires settling transactions in the same time intervals they are scheduled, priced or dispatched, along with aligning shortage pricing to work in the same intervals. While PJM already incorporates shortage pricing, staff realized the current system requires changes to ensure pricing signals aren't unnecessarily erratic. The RTO's problem statement goes beyond the requirements of the order to address these issues as well.

The original language of the final key work activity didn't sit well with some participants, who were concerned it might open the door for revising the demand curves rather than simply adjusting the pricing intervals within them. The language was updated prior to approval to read: "Develop a new set of steps within the demand curves to be implemented in the final rule, if necessary."

The debate went on for nearly an hour, leading PJM CEO Andy Ott to weigh in and assure members that the point was to avoid wild price fluctuations, not to adjust the overall rate structure.

PJM's plan is to smooth out the pricing signals over time so they only trigger shortage pricing when it's a trend.

"The look-ahead engine looks out over time, and it has to see the shortage for a persistent period of time before it will pass the indicator over to the [real-time schedule] engine," PJM's Rebecca Carroll said.

PJM has only had one incident of shortage pricing in recent memory, on Jan. 6-7, 2014.

Susan Bruce, who represents the PJM Industrial Customer Coalition, supported the focus on shortage pricing. Under the current demand curves, she said, consumers can be charged higher prices for a whole hour for a shortage that might last only five minutes.

Work on Fuel-Cost Policy Updates Moves Ahead

PJM market analysis manager Jeff Schmitt presented a timeline for the days remaining before the RTO's Aug. 16 deadline for making a FERC compliance filing on its fuel-cost policy protocols.

The Market Implementation Committee held a special meeting on July 27 and has another scheduled for Aug. 4. Schmitt said he hopes to have the language updated prior to the committee's regular meeting on Aug. 10. He asked that any additional feedback be sent to him.

In June, FERC ruled that PJM "lacks provisions for sufficient review of cost-based offers and could permit a resource to submit inaccurate cost-based offers." It ordered PJM to add to its Tariff and Operating Agreement a requirement that generators submit fuel-cost policies that are approved by the RTO prior to submitting cost-based offers, including a penalty structure for those that file inaccurate information (ER16-372).

Feedback from the MIC meetings will be used to update PJM's Manual 15. Schmitt said PJM has asked for a Dec. 1 effective date but that implementation of the new language will be based on when FERC responds.

MRC Endorses Manual Changes

Members unanimously approved the following manual changes:

- Manual 11: Energy & Ancillary Services Market Operations for the Day-Ahead Scheduling Reserve. Adds language excluding resources from the day-ahead scheduling reserve process that cannot reliably fulfill obligations in real time.
- Manual 14C: Generation and Transmission Interconnection Facility Construction. Changes support the inclusion of Order 1000 processes. Since the first reading, the new tie line section has been removed. Discussion on that issue will begin in August.
- Manual 20: PJM Resource Adequacy Analysis. Updates are the result of a periodic review.
- Manual 29: Billing. Clarifications and updates are the result of a regular review.

Manual Changes Clarify 'Physicality' of Transactions

MRC members endorsed changes to Manual 18 clarifying the rights and responsibilities involved in auction-specific bilateral transactions. (See "Members OK Clarifications to Preserve 'Physicality' of Auction-Specific Bilateral Transactions," *PJM Market Implementation Committee Briefs*.)

New PLS Exception Process Offers Flexibility

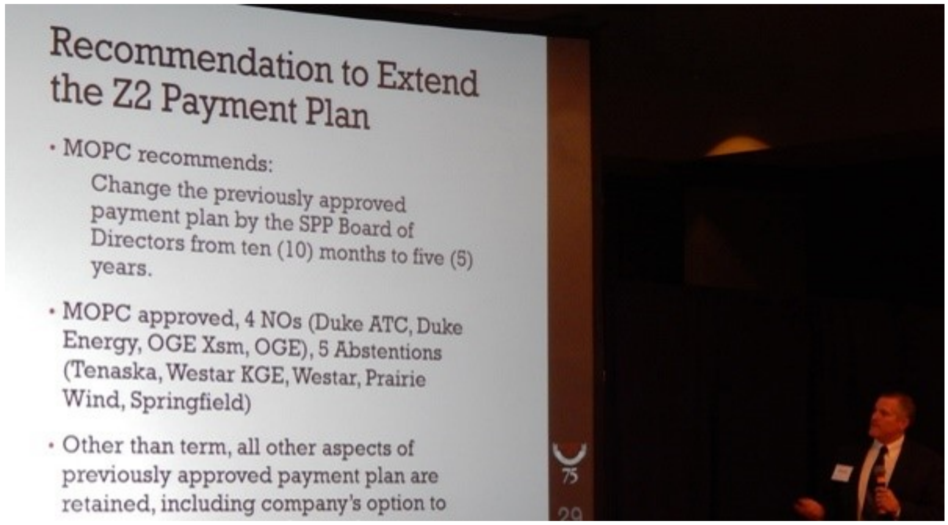
The Members Committee approved Operating Agreement and Tariff language giving more flexibility to the parameter-limited schedule exception process. (See "More Flexible PLS Process Approved," *PJM Markets and Reliability and Members Committees Briefs*.)

— Suzanne Herel and Rory D. Sweeney

SPP NEWS

Board Approves Z2 Timeline Extension, Creates Task Force for Further Study

By Tom Kleckner



SPP's Paul Suskie leads discussion on Z2 during the July 16 board meeting. © *RTO Insider*

RAPID CITY, S.D. — The SPP Board of Directors and Members Committee last week agreed to give transmission customers an extra 50 months to pay their Z2 bills while also creating a new task force to address complaints of members charged for costs that were not identified in service agreements.

The two actions illustrated the challenge of trying to ensure the equity of retroactively billing customers, the magnitude of the debts involved and the complexity of determining amounts to be billed and reimbursed under Tariff attachment Z2, which details how sponsors that fund network upgrades can receive reimbursements. Staff has identified $848.8 million in assigned costs from 158 creditable upgrade projects.

The board and members unanimously approved the Markets and Operations Policy Committee's earlier recommendation to extend the Z2 payment timeline from 10 months to five years and dismissed waiver requests previously rejected by the MOPC. (See *SPP MOPC Recommends 5-Year Timetable for Resolving $849M Z2 Bill*.)

Stakeholders also agreed to a suggestion by SPP CEO Nick Brown and directors Phyllis Bernard and Larry Altenbaumer directing MOPC Chairman Noman Williams to assemble a task force to find "a more rounded solution to this problem," as board Chairman Jim Eckelberger put it.

The actions all but ensure there will be an additional recalculation of Z2 credits and bills in the near future.

"Does that mean there's a round two coming? I believe it does," Eckelberger said. "We've got to find a way to be as inclusive and equitable as [the process] can be. We need to get this right."

The agreement short-circuited another contentious discussion on an issue that dates back to 2008, when SPP was to have begun crediting and billing customers for system upgrades in accordance with attachment Z2. Years of incorrectly applied credits have complicated the task of trying to accurately compensate project sponsors and claw back money from members who owe debts for the upgrades.

"We feel we are owed a significant amount of credits … our concern is the same it's always been," said NextEra Energy Resources' Mark Tourangeau, echoing comments by other members waiting on credit payments. "I would urge the board and all the stakeholders to think about equity from the folks who have to pay upgrade costs, the folks who are due credits and the folks who have to go back" and ask for payments.

"It's fair to say that when we signed service agreements, there was no indication the charges would be as high as what they are. The fact [that] the payment plan was recently extended shows the board didn't know either," said Stuart Solomon, COO of American Electric Power's Public Service Company of Oklahoma. "So as we were making decisions to enter power purchase agreements, we weren't making informed decisions. Every indication we had at that time was the costs wouldn't be at this level, as we were signing service agreements that didn't reflect all of these creditable upgrades."

"I feel like the red flag on the rope in a tug of war," SPP Director Bruce Scherr said. "There are compelling arguments on both sides, but I haven't moved. It leaves me really uneasy about how to vote."

"Our primary concern is … what did we know, and when did we know it?" said Les Evans of Kansas Electric Power Cooperative. "Frankly, going forward, I have concerns about how to do business with SPP as a customer. I signed a contract saying I have no direct assigned costs. Four years later, I have a bill for $6 million."

SPP staff agreed that customers should not be obligated to pay Z2 costs for resources that were not designated in the agreements before service began. Staff also said that sponsored upgrade costs should be allocated based on rules in effect at the time a credit payment obligation is assigned, rather than the rules in effect when an upgrade became creditable.

Staff is working to provide historical billing results for stakeholder review before the October MOPC meeting. The first invoices are scheduled to go out in early November.

"Frankly, going forward, I have concerns about how to do business with SPP as a customer. I signed a contract saying I have no direct assigned costs. Four years later, I have a bill for $6 million."

Les Evans, Kansas Electric Power Cooperative

SPP News

Board of Directors and Members Committee Briefs

Members Facing 4-Cent Increase in Admin Fee

RAPID CITY, S.D. — Less than a year after enjoying a 2-cent reduction in SPP's administrative fee, the RTO's members are now facing the prospect of a 4-cent hike for 2017.

SPP's Finance Committee announced the increase during last week's Board of Directors and Members Committee meeting to minimal pushback. Members — with only three opposing votes — and the board approved the committee's recommendation to hike the fee's cap to 43 cents/MWh, which would allow room to raise it from its current 37 cents/MWh to a projected 41.1 cents/MWh.

The board's approval means staff can file the necessary Tariff changes with FERC.

Staff said the move was necessary because the RTO expects 2016 expenses to exceed revenues by $6.7 million as a result of a 3.7% drop in peak loads since 2015.

SPP is forecasting revenue from the fee will be $5.4 million below budget for the year. Staff said raising the fee's cap above 2017's projected level would "accommodate any further reduction in peak load similar to what SPP utilities experienced in 2015."

The committee said it will review the fee's billing determinants to see "if a more predictable and equitable basis exists to allocate SPP's costs of operations to its customers."

"The admin fee is one of the places where the rubber hits the road," said Oklahoma Gas & Electric's Greg McAuley. "We just got done with a rate case, and I can tell you it is very, very difficult to raise rates."

SPP's addition of the Integrated System last October was expected to help keep the fee stable. However, the system's reported loads have been 10% below expectations; SPP projected a 12% increase in transmission load last year with the system's membership. (See <u>SPP Board Approves Budget, SPC Expansion</u>.)

"We thought we would bring the number down 5 cents with IS, but it actually brought them down by 3," Board Chairman Jim Eckelberger said.

"The costs in all of this equation didn't change very much," SPP CEO Nick Brown said. "The load in the footprint changed a lot, so what we're collecting from each market participant will be roughly the same, regardless of what that rate is. It's just the denominator" that changed.

This year's budget assumed transmission volume of 407.2 million MWh. SPP's draft 2017 budget projects 395 million MWh.

The Finance Committee said the 2017 budget still includes "several unknowns," primarily because SPP has just started its 2017 planning process. A final budget will be presented to the board during its December meeting, when members will also vote on next year's administrative fee.

Committee Chairman Harry Skilton noted that one favorable variable is the scorching summer heat that's settled over the Great Plains. Skilton said SPP's manpower costs have resulted in a $1.2 million hit above costs, "but we will carry on."

Cybersecurity Insurance

Skilton also said cybersecurity insurance is becoming an available product, remarking, "Anything can be insured." He said his committee will meet with Little Rock-based Stephens Insurance "once that market is a little solidified" as part of SPP's overall insurance package.

Following the committee's recommendation, members unanimously approved the selection of SPP's controls, financial and benefit plan auditors KPMG, BKD and Thomas & Thomas. Members also authorized Brown and CFO Tom Dunn to negotiate the origination of a $30 million line of credit.

First Competitive Tx Project Pulled; ND 345-kV Line Approved

SPP members and its board wasted little time in approving the withdrawal of SPP's first competitive project under FERC Order 1000, the 22.6-mile, 115-kV line from Walkemeyer to North Liberal in southwest Kansas. (See <u>SPP Cancels First Competitive Tx Project, Citing Falling Demand Projections</u>.)

The group also approved modifying Basin Electric Power Cooperative's notice to construct (NTC) for a 33-mile line between two substations in western North Dakota. The modification will allow Basin Electric to build the Kummer Ridge-Roundup project — part of a larger project that is already under construction — as a 345-kV line, a motion rejected two weeks ago by the Markets and Operations Policy Committee.

The project is expected to cost $61 million as a 345-kV line, compared to $54 million at 115 kV. Staff determined the 345-kV version performed better over a 10-year planning horizon, given projected 2.5% annual load growth driven by the nearby Bakken shale play.

Mike Risan, Basin Electric's senior vice president of transmission, called the region the "sweet spot of the Bakken," though field loads have proven to be volatile with the price of oil.

"The load is still coming here," he said. "We have a pent-up demand from a number of wells already drilled and waiting to frack."

Several members questioned whether Basin Electric was trying to run around SPP's planning process by having the project — which was planned before the utility joined the RTO last year as part of the Integrated System — zonally allocated when it could be considered a regional project.

"We're not trying to beat the system," Risan said, saying the company was balancing serving load, planning for the future, transitioning to SPP and understanding new processes at the same time.

Bob Harris, senior vice president and regional manager of the Western Area Power Administration's Upper Great Plains Region, stuck up for his fellow new member.

"The IS facility inclusion process was more restrictive than the SPP planning process," he said. "I would submit if we had been part of SPP and part of SPP's planning process back when we began this plan, it would have been in the SPP plan. It's only because of the transition [to SPP] that we're in this dilemma."

SPP's vice president of engineering, Lanny Nickell, said staff did not previously identify Kummer Ridge-Roundup as a "regionally needed" project, and it believes the project should be treated as a sponsored upgrade. "We didn't determine any regional needs in the study."

However, Nickell acknowledged that with its increased capacity, the line could have benefits that address regional needs identified in SPP's Integrated Transmission

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Planning's 10-year assessment.

"As I understand our model-build process, this project was not assumed to be built at 345, so it's possible some of those ITP10 needs will go away."

Most members agreed with the 345-kV solution. "I think that's the best plan of action," Xcel Energy's Bill Grant said.

The board altered another MOPC recommendation from two weeks ago when it delayed until next quarter a decision to withdraw an NTC for American Electric Power's $31 million rebuild of a 69-kV line in West Texas. Nickell said SPP is working to confirm AEP's contention that the line suffers from congestion, saying reliability coordinators have not been able to observe the congestion in real time.

"AEP has addressed congestion on the line locally. Our findings may not necessarily change our recommendation to the board, but the situation warrants further investigation to accurately identify the frequency and significance of the congestion," Nickell said.

The board and members also unanimously approved issuing an NTC for AEP's rebuild of a 138-kV line near Shreveport, La. The project was initially expected to require a reactor, but that NTC was withdrawn, saving $3.55 million.

SPP Making FERC-Directed Changes to MMU

Oversight Committee Chairman Joshua W. Martin III told the board and members that SPP's Market Monitoring Unit is well into the process of implementing changes recommended by FERC's recent audit of the unit's independence.

The commission last month released a report on its 17-month inquiry into the MMU, listing 16 recommendations to improve its independence. (See FERC Calls for Changes to Protect SPP Market Monitoring Unit Independence.)

Martin said the committee has begun holding "MMU-only" meetings, "consistent with the direction we got from FERC."

He also said SPP has begun plans for the physical separation of the MMU from RTO staff, also recommended by FERC. Martin said it would be similar to the Regional Entity's setup with SPP's headquarters building, which requires key-card access and only allows RTO employees entrance when accompanied by an RE employee.

"There were a number of findings and recommendations that frankly were minor, in my opinion, considering the length of time and resources that went into this audit," Martin said. "We were able to demonstrate we have a good structure and operate efficiently."

CEO Brown noted FERC found no instances of the RTO "exerting inappropriate influence" on the MMU.

The committee has also begun discussing plans to replace MMU Director Alan McQueen, who has agreed to delay his retirement until 2017.

MMU Shares Draft State of the Market Report

McQueen shared a draft report of the MMU's 2015 State of the Market report, the second such evaluation since the Integrated Marketplace went live in 2014.

According to the report, the Integrated Marketplace is a "significant maturing" market reflected in high levels of participation, lower levels of make-whole payments

McQueen

and mitigation compared to other markets, and a modest level of scarcity pricing. The MMU said the market was affected by continually declining natural gas prices, increasing wind generation capacity and output, and declining levels of overall congestion, but with increased congestion in wind-generation areas.

Wise

Golden Spread Electric Cooperative's Mike Wise disagreed with the report's assertion that a "vast majority" of market participants running combustion turbines are able to recover their avoidable operations and maintenance costs.

"That is just not true. One of the reasons make-whole payments are so low is because you're not allowing combustion turbines to get those start-up charges," Wise said. "You have the view these are long-term charges. Is there an opportunity for us to continue this dialogue, not just Golden Spread, but all market participants?"

"We've had this discussion about the differences between what's being used in mitigation and what's being collected by any resource," McQueen responded. "My disagreement with your interpretation of variable O&M is different when it comes to short run.

"I'll reiterate my offer to look at specific units," he continued. "If someone wants to come forward and have us look at those costs and see whether there's adequate revenue on an annual basis, we'd love to have that conversation. The MMU can't do it alone."

Eckelberger closed the discussion by suggesting to McQueen that the final report include language indicating "the membership doesn't agree with your conclusion."

Board Approves Maher, Whitley as New RE Trustees

The board doubled the size of the RE's trustees by approving the nomination of

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"There were a number of findings and recommendations that frankly were minor, in my opinion, considering the length of time and resources that went into this audit."

Joshua W. Martin III, SPP Oversight Committee chairman

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industry veterans Mark Maher and Stephen Whitley. The two were selected from an initial field of 22 candidates and will join Dave Christiano, the trustees' chair, and fellow trustee Gerry Burrows.

"The two best candidates we thought we had," Christiano told the board and members.

Both new trustees bring ample RTO leadership experience, Maher as former CEO of the Western Electricity Coordinating Council, and Whitley as NYISO's former president and CEO and ISO-NE's former COO.

Maher retired from WECC in 2014 after eight years of service. Before that, he was vice president of transmission services for PacifiCorp, where he was responsible for strategic and operational planning, developing transmission policy and ensuring FERC compliance. He also served as senior vice president at the Bonneville Power Administration. He is a graduate of the University of Washington.

Whitley served as NYISO's CEO between 2008 and 2015 and was the COO and a senior vice president at ISO-NE from 2000 to 2008. He also spent 30 years at the Tennessee Valley Authority after earning an electrical engineering degree from Tennessee Technological University. He is a retired colonel in the U.S. Army Reserve.

Brown: Market Savings to Top $1B Before Year's End

Brown said the Integrated Marketplace is on track to top $1 billion in accumulated savings by year-end. During his regular report, Brown said the markets yielded $802 million in net savings in 2014-15, after having opened in March 2014.

SPP did not add any new market participants during the quarter. The markets currently have 172 participants, with 110 registered as financial-only and 62 as asset-owning.

Brown also said SPP has responded to the Mountain West Transmission Group's request for proposal to develop an organized market. The group consists of a number of SPP members. (See Mountain West RTO Could Pose Competition for CAISO.)

Consent Agenda

The board's consent agenda included issuing an NTC for a 17-mile, 115-kV line in West Texas (Mustang-Seminole) that was identified as a short-term reliability project in the 2016 ITP Near-Term assessment. The project could have been competitively bid, but because it has short-term reliability needs, it was awarded to the incumbent.

The board also re-set the baseline costs for a pair of projects both more than 20% under budget: a 69-kV Westar Energy rebuild and a 138-kV Mid-Kansas Electric transmission project.

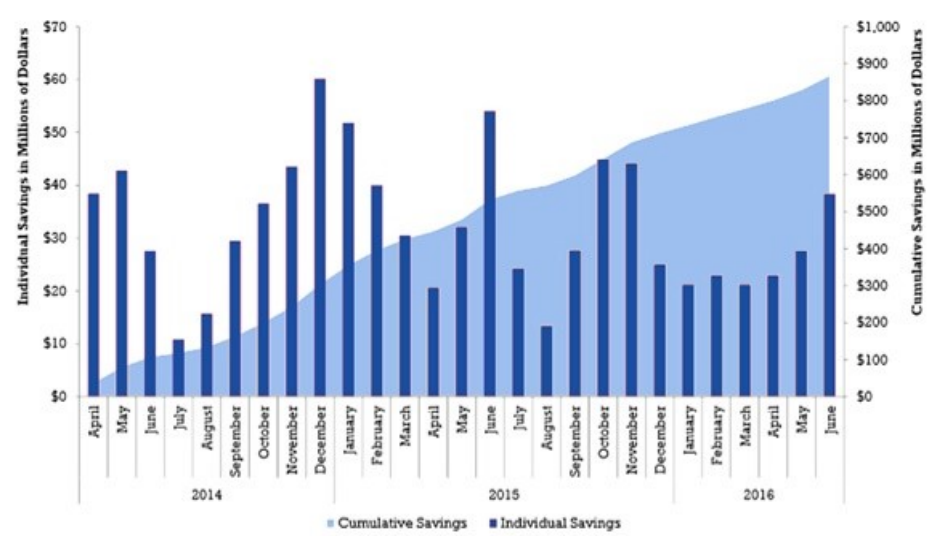
The board also approved modifications to NTCs for four network upgrades, reducing the required emergency ratings, and approved a modification to a Nebraska Public Power District NTC for a new 345/115-kV transformer and a 22-mile, 115-kV line that resulted in no price change.

Eight revision requests were included on the consent agenda:

- MWG-RR 7 MPRR155, revising instructions for dispatching generators out of merit order into two categories: reliability issues and emergency conditions.
- MWG-RR 153, eliminating the requirement that market participants make two separate submissions for a single intra-day change.
- MWG-RR 161, changing the method for calculating make-whole payments for multi-configuration combined cycle resources; the new rules allow use of a netting approach in calculating the commitment-level costs eligible for recovery.
- MWG-RR 166, removing references from the protocols and Tariff to the interim transmission congestion rights process developed for the transition into the Integrated Marketplace.
- MWG-RR 167, avoiding Tariff violations resulting from the incorrect submission of annual revenue rights or TCRs.
- ORWG-RR 159, moving requirements regarding the outage-coordination function into SPP Operating Criteria Appendix OP-2 "Outage Coordination Methodology," eliminating redundant language elsewhere.
- RTWG-RR 160, clarifying the ITP manual to note which generation interconnections and associated upgrades are required to be modeled in ITP assessments.
- RTWG 163, correcting Tariff language to specify that the ITP manual includes references to requirements.

RR 165, which removes references to the retired Mitigated Offer Task Force from the Tariff's Appendix G, was removed from the agenda because it does not require board approval.

— Tom Kleckner



Integrated Marketplace cost savings *Source: SPP*

SPP NEWS

SPP, MISO No Closer to Day-Ahead FFE Exchanges

By Amanda Durish Cook

Negotiations with MISO over the exchange of day-ahead firm flow entitlements "are proving to be more difficult than originally expected," SPP told FERC in its third informational report on the RTOs' market-to-market coordination (ER13-1864).

The RTO said it continues to review MISO and PJM's new day-ahead FFE exchange process and collect daily data from MISO. However, "SPP's experience with the real-time market-to-market coordination procedures and the ensuing negotiations with MISO to try to improve those procedures has reinforced SPP's belief that it would be premature to implement a day-ahead firm flow entitlement exchange process at this time," it told the commission. (See "Regions Begin FFE Exchanges," *MISO/PJM Joint and Common Market Meeting Briefs*.)

SPP said it was concerned about the potential impacts on its transmission congestion rights markets. "SPP needs to be reasonably certain that the firm flow entitlements being exchanged will result in equitable and efficient operational and settlement outcomes," it said.

The RTOs have fared little better on implementing interface bus pricing, SPP said. It attended preliminary analysis presentations given by both MISO and PJM and discussed the issue separately with staff members of each RTO. The results, SPP said, make it unsure that the PJM-MISO seam is comparable with SPP and MISO's.

Instead, SPP said, the RTOs are planning a study that would examine interface consistency, gaming opportunities, equity concerns and flow issues. The study is expected to begin in September and wrap up by the end of the year.

Despite the apparent lack of progress, SPP said it was interested in continuing its analysis of the MISO-PJM processes and working with both RTOs.

SPP's informational reports were mandated by FERC in a January 2015 order. Reports are due every six months until the RTOs reach an agreement.

NextEra Energy Reaches Deal for Oncor

Energy Future Holdings Wins on Tax Question

By Rory D. Sweeney

NextEra Energy announced Friday morning that it had reached an agreement to buy cash-strapped Energy Future Holdings' profitable Oncor assets in a deal that values the Texas transmission and delivery subsidiary at $18.4 billion.

The sale, along with a favorable tax decision also announced Friday, would move EFH closer to an exit from its Chapter 11 bankruptcy, which it declared in April 2014.

The deal for Oncor — Texas' largest utility, with 119,000 miles of distribution and transmission lines and more than 3 million meters — also bolsters NextEra's position as a player in the Texas energy market. It has been involved in Texas since 1999 through transmission provider Lone Star Transmission.

NextEra CEO Jim Robo said he plans to continue business as usual at Oncor, which he called "one of the most efficient, reliable and low-cost utilities in the nation."

"We are incredibly impressed by Oncor's management team and its employees, and we are committed to retaining the Oncor name, its Dallas headquarters and local management," Robo said. "NextEra Energy shares Oncor's strategy of making smart, long-term investments in transmission and distribution."

Approvals Needed

The sale must be approved by both the Public Utility Commission of Texas and a federal bankruptcy court. If approved, it would divest EFH of its 80% stake in Oncor for about $14.9 billion, NextEra said. The deal would be primarily cash, along with some NextEra stock, according to an 8-K EFH filed Friday with the U.S. Securities and Exchange Commission.

The deal can be canceled if the PUCT's approval includes any of several conditions that the agreement outlines as overly "burdensome" or if it hasn't closed by March 26, 2017, though there is the potential for a 90-day extension.

Although EFH is allowed to seek other offers, it would be on the hook for a $275 million termination fee if the NextEra deal receives PUCT and court approval and EFH eventually sells to someone else.

Other Suitors

That creates a hurdle for other rumored Oncor suitors, including Berkshire Hathaway Energy, Fidelity Management, Edison International and Hunt Consolidated. Also interested was the investor group led by Borealis Infrastructure Management and Singapore's GIC Special Investments that together own the other 19.75% of Oncor. (See *With Oncor Back on the Market, Multiple Suitors Line Up*.)

Hunt remains optimistic, releasing a statement that called the announcement "not a surprise and, as we know, is just another step in a very long process."

"Hunt will remain involved as the process unfolds, as the advantages of maintaining ownership of Oncor by Texans for Texans are clear," Hunt spokeswoman Jeanne Phillips said.

Hunt previously appeared to be a frontrunner for Oncor, but its bid foundered in May when the PUCT imposed conditions it said were unacceptable. Hunt has since sued to reopen the case. (See *Hunt Reopens Oncor Bid in Lawsuit Against PUCT*.)

Tax Liability Eliminated

EFH's 8-K also announced a favorable ruling from the Internal Revenue Service that eliminates a potential $4 billion tax liability for its remaining assets.

EFH has proposed a separate path for its Luminant generation arm and TXU Energy retailer, selling them to senior creditors who are owed $24.4 billion. Bankruptcy court hearings on the proposed sales are scheduled to begin Aug. 17 in Delaware.

NextEra's Other Moves

NextEra also announced on Friday that its competitive energy subsidiary, NextEra Energy Resources, is selling its interests in two Pennsylvania gas-fired generation plants to a Connecticut-based investment firm for $760 million.

Starwood Energy Group Global, which focuses on gas-fired and renewable generation, transmission and storage facilities, agreed to buy the 790-MW combined cycle Marcus Hook Energy Center and the 50-MW simple cycle Marcus Hook 50 Energy Center in Marcus Hook, Pa.

NextEra says the sale, which is expected to close in the fourth quarter of 2016, will result in net proceeds of approximately $255 million after repayment of the existing project-related financing.

DTE Expects Boost from Southwestern's Rig Expansion

DTE Energy raised its 2016 earnings per share guidance from $4.80-$5.05 to $4.91-$5.19 and said the addition of two new drilling rigs in the Utica Shale could boost profits further still.

Houston-based oil and natural gas company Southwestern Energy recently announced it will add five rigs by the end of the third quarter, two of which will be in the DTE-serviced Utica Shale basin, which could boost DTE's gas storage and pipeline business segment.

Southwestern drill rig *Source: Southwestern Energy*

The expected increase in drilling activity was excluded from DTE's revised earnings guidance, which reflected better-than-expected second quarter results. But DTE CFO Peter Oleksiak said during an earnings call last week that the rigs "may provide upside to 2016" earnings and also will aid 2017 results.

DTE reported second-quarter operating earnings of $177 million ($0.98/share), up from $137 million ($0.76/share) in 2015. DTE's gas segment earned $35 million, up $10 million from a year earlier.

— Amanda Durish Cook

Exelon's Constellation to Buy Con Ed Subsidiary's Retail Operation

Crane: Won't Use Debt in Acquisitions

By Ted Caddell and Rich Heidorn Jr.

ConEdison Solutions Large and Small Business Territories *Source: ConEdison Solutions*

NASHVILLE, Tenn. — Exelon's Constellation Energy Resources unit is buying Consolidated Edison's retail energy business as it continues its efforts to hedge against falling wholesale power prices.

Constellation's purchase of the retail division of ConEdison Solutions will give it another 560,000 residential, commercial and business electricity and natural gas customers in Texas, D.C. and 12 states in the Northeast, Mid-Atlantic and Midwest. If completed, it will make Constellation the largest competitive energy supplier in the U.S., with 2.5 million customers. Terms of the deal were not disclosed.

"This agreement provides an opportunity to grow our retail electricity and natural gas business in strategically attractive markets where we're best suited to match load served with Exelon generation assets," Constellation CEO Joseph Nigro said. "ConEdison Solutions has a reputation for delivering value to customers, and our combined companies will continue that tradition with a broad array of energy products and services at competitive prices."

"With their industry-leading position, we are confident that the retail electricity and natural gas business will continue to thrive as part of Constellation," ConEdison Solutions CEO Mark Noyes said. "This move will enable our company to focus our attention and our resources on making energy services and renewable energy offerings even more competitive and well-positioned for rapid growth."

Having guaranteed customers for its wholesale generation fleet protects the company from volatility in wholesale prices. It was the company's efforts to minimize price risk that also led Exelon to its $6.8 billion purchase of Pepco Holdings Inc. this spring. The addition of PEPCO, Delmarva Power and Atlantic City Electric brought Exelon's customer base to 10 million.

No More Debt

Exelon CEO Chris Crane gave no hint of the Con Ed deal in an appearance Monday at the National Association of Regulatory Utility Commissioners' summer meeting.

In an interview with NARUC President Travis Kavulla, Crane said the company would not seek debt-financed acquisitions despite the current low interest rates.

Independent power producers who seek greater leverage when interest rates are low can find themselves squeezed when rates rise, he said.

"We operate in probably a little bit more conservative way," he said. "Our focus is actually reducing debt and maintaining a strong capital structure and understanding we're at a low point in the [interest rate] cycle. It would not be prudent to think that this is a sustainable environment going forward."

Level Playing Field

Meanwhile, Exelon is seeking help from state officials to eliminate the losses at its nuclear plants in Illinois and New York.

The company said in June it will close its Clinton and Quad Cities nuclear plants after the Illinois General Assembly adjourned without acting on a bill that would have subsidized the money-losing stations. (See *Exelon to Close Quad Cities, Clinton Nuclear Plants*.)

Crane said the company wants to preserve the plants' 4,200 jobs — "The tax base for DeWitt County dries up and goes away if the Clinton plant shuts down," he said — but can't continue to absorb the losses.

In New York, where the company has three nuclear plants, it had offered to buy Entergy's struggling FitzPatrick plant if state regulators completed a plan to subsidize them. (See related story, *New York Adopts Clean Energy Standard, Nuclear Subsidy*, p.1.)

Crane said the company has had a "very productive dialog" in New York, adding that the zero-emission credits would create a "level playing field for carbon-free generation."

"If other states that our … nuclear assets [operate in] want to approach the market like that, we would like to do that," he said.

Southern California Edison Preparing for Distributed Energy Future

By Robert Mullin

Edison International is maneuvering to capitalize on California's effort to meet its greenhouse gas emissions goals and encourage the use of distributed energy resources.

The 2018-2019 rate case for subsidiary Southern California Edison will include a capital spending request "designed to help California achieve its low-carbon policy objectives and to enable customer choice," Edison CEO Ted Craver said during a call with investors last week.

Edison's second-quarter profits fell 27% to $276 million, in part because year-ago earnings reflected a $100 million income tax benefit.

The second quarter of 2015 also included revenue SCE later refunded to ratepayers after a delayed ruling from state regulators on its 2015 rate case.

As a result, the company said, any comparison between the two quarters was "not meaningful."

Craver said SCE's rate base is projected to grow 7% over 2016-2017 based on capital spending approved by the California Public Utilities Commission and expected spending on FERC-jurisdictional transmission projects.

While the company expects "relatively little variance" in the timing of its spending on CPUC-jurisdictional projects, it could experience some "variability" in the timing for its FERC projects, which Craver attributed to delays in routing decisions and state and federal permitting approvals.

"A recent example was the $1.1 billion West of Devers project, which has been something of a moving target with CPUC staff — even with CAISO support — but appears ready for final CPUC approval with a supportive alternate proposed decision pending," Craver said.

Project delays could defer some spending planned for 2017 to subsequent years, he said, but SCE does expect to complete major transmission projects linking the utility's service territory with renewable generation located farther inland.

Edison anticipates a future shaped by 2015 legislation that seeks to use the grid to help meet the state's carbon reductions goals, including reducing vehicle emissions through electrification of the fleet. One byproduct of that law is a current CPUC proceeding that seeks to direct utility investment to facilitate the wider adoption of DER.

In response, capital expenditures will be "lumped into two buckets" in the rate case SCE intends to file with the CPUC on Sept. 1.

The first bucket will consist of "traditional" investments, such as replacing aging infrastructure, adding new customer connections, upgrading information technology and maintaining SCE's generators. The second will reflect investments in the modernization of the utility's distribution system to facilitate the growth of DER.

Craver said the CPUC has "provided only some early direction on preferred technologies and required investments" for modernization.

Through its upcoming rate case, SCE will be the first utility "to provide specificity for how this technology evolution should unfold," Craver said.

While Craver said he wouldn't divulge details ahead of the filing, he noted that some of the utility's modernization investments amounted to reinforcing the existing system, such as upgrading low-voltage circuits to accommodate increasing amounts of DER.

"But other parts really have no precedent, and therefore we do not know how to handicap how much of our request might finally be approved," Craver said.

PG&E Sees Transmission, Distribution Role in 'Clean Energy Future'

By Robert Mullin

Pacific Gas and Electric's second-quarter profits fell sharply because of a series of one-time costs — most related to the company's natural gas business.

Still, the company sees bright prospects for its electricity business as California moves to aggressively reduce greenhouse gas emissions and increase reliance on renewable generation.

The company reported net income of $206 million, down from $402 million a year earlier. Earnings per share fell from 83 cents to 42 cents. Adjusted earnings came in at 66 cents, far short of the average analyst estimate of 93 cents.

The one-time items included penalty costs stemming from the San Bruno pipeline explosion in September 2010. The company's federal criminal trial for the incident went to a jury last week.

"We continue to believe that no PG&E employee knowingly and willfully violated the law," CEO Tony Earley said during a call with analysts to discuss earnings. "But now it's in the hands of the jury."

Earley said mandates stemming from last year's passage of California SB 350 "will influence both our procurement needs and investment opportunities." The law raised the state's renewable portfolio standard to 50% by 2030 and imposed increased energy efficiency requirements for buildings.

Efficiency gains will translate into declining energy demand in PG&E's service area, Earley noted. The company also expects to lose some customers to community choice aggregators, which could seek to procure electricity from other suppliers.

PG&E will also have to cope with the rapid adoption of residential rooftop solar in California.

"We'll have to continue to upgrade the distribution grid to handle increasing amounts of distributed generation," Earley said.

PG&E
Pacific Gas and Electric Company®

On top of that, the company will require new and upgraded transmission lines to support the utility-scale renewables necessary to meet the state's 50% RPS. The company is seeking an additional $100 million in capital expenditures through its 2018 transmission owner rate case filed with FERC last week, Earley said.

In April, PG&E established a strategic alliance with TransCanyon — a joint venture between Berkshire Hathaway Energy and Pinnacle West — to pursue competitive transmission projects solicited by CAISO. The arrangement "will allow us to compete in not just our service area, but the broader CAISO," PG&E President Geisha Williams said.

"We're well positioned to help drive California's clean energy future through sustained investment," Earley said.

Akins: AEP Wants Only Partial Restructuring of Ohio Market

By Tom Kleckner

American Electric Power CEO Nick Akins said last week the Columbus-based energy giant is seeking only a partial "restructuring" of Ohio's energy market, not full reregulation.

After FERC ruled in April that it would review state actions to guarantee income for some of AEP's Ohio power plants, Akins had said the company would lobby Ohio lawmakers for reregulation of the state's electricity market while also considering selling off its Ohio fleet. (See *All Eyes on AEP, FirstEnergy with Ohio PPAs in Doubt*.)

Asked during a July 28 call with analysts whether AEP was de-emphasizing "reregulation" of the market, Akins said, "Reregulation just has a larger connotation to it and actually is a much heavier lift to put the entire genie back in the bottle.

"With FERC's order essentially taking the Ohio [power purchase agreement] proposal approved by the Ohio commission off the table, which I discussed last quarter, AEP is addressing the situation by pursuing restructuring in Ohio," he said. "Note this is restructuring, not reregulation."

AEP's Dresden gas plant in Ohio *Source: AEP*

Akins said state lawmakers and other power generators are discussing the company's proposed legislation that would transfer its competitive power generation to its AEP Ohio subsidiary. The legislation would also allow AEP to invest in new natural gas and renewable energy power sources.

"The proposed legislation strikes a balance between our ability to invest and maintain generation in the state and the customers' ability to choose generation suppliers," Akins said.

AEP has said it won't build new gas plants in the state and would sell all its Ohio plants if the legislature is unable to come up with a solution. The Public Utilities Commission of Ohio had approved the earlier guaranteed-income proposal after almost two years of debate.

The company reported a quarterly profit of $502 million ($1.02/share), up from $430 million ($0.88/share) a year ago. It reported sales of $3.9 billion, up slightly from $3.8 billion. Akins said AEP's focus on process improvement, cost discipline and capital allocation "gives us confidence that we can achieve operating earnings within our guidance range of $3.60 to $3.80 per share for 2016."

AEP stock closed up at $69.30 Friday, an increase of 43 cents since the earnings announcement.

FirstEnergy Posts $1.1 Billion Loss, Eyes Exit from Merchant Generation

Continued from page 2

In testimony, the company warned that it could receive a credit downgrade without the increase in revenue. Their latest rider plans, Mikkelsen said, would provide a "more reliable hedge against increasing market prices by using proxy costs and generation capacity and output for diverse generation in the marketplace without reference to any particular generating facilities."

"By 'priming the pump,' the companies will be able to obtain lower financing costs when grid modernization spending begins, resulting in lower rates for customers," she said.

Although the rider would be, in part, to fund grid modernization projects, she said the company should be able to collect it before that work commences.

Jones said during the analyst call that the company expects a ruling from PUCO by September. He declined to say what they would do if PUCO rules against the company.

"When we know that outcome, we will let you know what the impact is on our credit ratings," he said. "We have a number of other strategic options we can execute, but it is premature to speculate.

FirstEnergy headquarters in Akron, Ohio

"We are focused on keeping our investment-grade rating of our holding company and the rest of our regulated entities," he said. He said there would be no large infusions of capital in the merchant business in any attempt to shore up its sagging credit rating.

Another company facing the same economic pressures relating to low wholesale prices, American Electric Power, has said it will devote its energies to "reregulating" the energy market in Ohio. Jones said he is "pulling for" AEP's efforts, but "at this point in time, we are not actively joining in with them."

Critics Blast Rider Plans

To FirstEnergy critics, the new testimony is hard to swallow.

"FirstEnergy's recent testimony asks the PUCO to reject the staff's criticism of — and embrace — its proposal for a 'virtual PPA,' in which the utility's distribution subsidiary would receive what the Ohio Consumers' Counsel estimates would be some $4 billion over eight years," said Dick Munson of the Environmental Defense Fund.

"FirstEnergy's level of greed is laughable, if it were not so seriously expensive for Ohio consumers ... and should be completely rejected," he said.

"The customers should not be providing credit support, and without serious restrictions, there is nothing to ensure it will not be just the same type of bailout" it already failed to get, Earthjustice's Fisk said.

Company Briefs

Mississippi Power Announces Another $9M in Kemper Overruns

Mississippi Power said last week its Kemper County coal-gasification plant will tally up another $9 million in overruns, a cost that the company promised to absorb.

The coal gasification plant now carries a $6.8 billion price tag, more than double its original estimate. Parent entity Southern Co. is responsible for $2.5 billion of the overall cost and wrote off $38 million before it announced its quarterly earnings last week. Southern said it spent $23 million on the Kemper plant in the second quarter.

Mississippi Power said the plant, designed to capture carbon dioxide emissions from coal, is scheduled to be completed by Sept. 30, but the company said it could announce further delays later this month. The plant is currently generating electricity by burning natural gas.

More: *The Associated Press*

Consumers Proposes Charging Station Network in Rate Request

Consumers Energy is proposing to construct a statewide electric vehicle charging network as part of its pending rate increase request before the Michigan Public Service Commission. The utility wants to install more than 800 charging stations at a cost of $15 million to its ratepayers.

Consumers spokesman Brian Wheeler said the plan would address the lack of public charging stations, earn Michigan recognition in renewable transportation and make residents more comfortable with the idea of purchasing an EV.

While stakeholders are generally supportive of the plan, advocates say Consumers should structure charging rates so EV owners see a savings over purchasing gasoline. Some also question whether general ratepayers should subsidize utility investments, including EV infrastructure.

More: *Midwest Energy News*

Ameren to Fund $2M in Clean Projects Under Settlement

Ameren Missouri and the Sierra Club have reached a settlement over the environmental group's allegations that Ameren had repeatedly violated the Clean Air Act at three coal-fired plants.

The agreement, filed in U.S. District Court, requires Ameren to create a $2 million fund for "environmentally beneficial projects." The Sierra Club said that the money will be split among community solar projects and a clean electric bus program in the St. Louis area.

The Sierra Club alleged that Ameren committed nearly 8,000 emission violations at its Labadie, Meramec and Rush Island plants from 2009 to 2013. The group said it settled partly because Ameren promised to take steps to retire the Meramec plant by 2022.

More: *Sierra Club; St. Louis Public Radio*

ICF Signs $11M Deal to Help KCP&L Customers Go Green

Global consulting and technology service provider ICF International has signed a three-year, $11 million contract with Great Plains Energy to support subsidiary Kansas City Power and Light's residential energy-efficiency programs.

ICF will educate customers about the programs, which include heating and cooling rebates, a LED discount and income-eligible multifamily rebates.

"ICF helps us get [the] word out to customers in hopes of changing that behavior," a KCP&L spokesperson said.

More: *Kansas City Business Journal*

NIPSCO Expands Indiana Car Charging Station Network

Northern Indiana Public Service Co. installed a public electric vehicle charging station last week at the offices of the Northwestern Indiana Regional Planning Commission in Portage.

The charging station is part of the utility's two-year-old IN-Charge Around Town program, which encourages drivers to go electric. The utility has installed 80 stations throughout northern Indiana. The commission's new charging station is free to use.

More: *Post-Tribune*

FirstEnergy Completes Demolition of Burger Plant

FirstEnergy on Friday demolished an 854-foot concrete stack and the last remaining building at the former coal-fired R.E. Burger Power Station in Ohio.

The company plans to transfer the property to PTTGC America if the latter decides to construct an ethane gas cracker plant on the site.

The Burger plant, which began operating in 1944, was retired in 2011.

More: *FirstEnergy; The Times Leader*

MidAmerican to Build Iowa's Largest Wind Project

The developers of what is billed as Iowa's largest wind energy project reached agreements with major customers, including Google, Facebook and Microsoft, that will allow the facility to go forward.

Commercial customers had objected to some terms of the development, including the return on equity demanded by MidAmerican. The developer wanted 11.5%, the customers proposed 9.5% and they settled on 11%.

A final decision from state regulators on the 2,000-MW Wind XI project is expected in September, with construction to begin in December. Construction must begin by Dec. 31 in order for the project to receive the maximum federal production tax credits.

More: *Midwest Energy News*

Federal Briefs

Constitution Pipeline Gets Extension from FERC

FERC has granted the developers of the Constitution Pipeline an additional two years to complete the project.

The developers said they needed an extension while they appeal the denial by New York environmental officials of a required water quality permit under Section 401 of the federal Clean Water Act. (See *Constitution Pipeline Appeals Rejection of Water Permit*.)

FERC originally approved the project in 2014, with the condition that it be placed in service within 24 months. The extension gives developers a new deadline of Dec. 2, 2018. The pipeline would deliver Marcellus Shale natural gas from Pennsylvania to pipelines serving New York state and New England.

More: *CP13-499*

WCS Providing NRC More Info on Nuke Storage Site

Waste Control Specialists began supplying the Nuclear Regulatory Commission more information about the company's plans to store high-level nuclear waste in Andrews County, Texas, after a letter from the commission fueled opponent groups' criticisms.

The letter from Mark Lombard, director of NRC's division of spent fuel storage and transportation, told WCS that its application for the project was deficient and requested more technical data. Opponents said the letter reflected unpreparedness on the part of the company.

WCS officials responded by clarifying the company only wants a license to store spent nuclear fuel rods using a dry-cask design and method already approved by the commission. The company plans to store 5,000 metric tons in the first decade but is seeking approval to store up to 40,000 metric tons.

More: *Odessa American*

Tribe Sues Corps of Engineers Over Dakota Access Permits

The Standing Rock Sioux Tribe of North Dakota and South Dakota is suing the U.S. Army Corps of Engineers for issuing permits for a crude oil pipeline it says threatens sacred sites and its drinking water supply.

The suit, filed in a federal court in D.C., alleges that the Corps' approval of the Dakota Access Pipeline is illegal, as it ignored risks to the environment and tribal sites. The pipeline, which would deliver North Dakota crude oil to terminals in Illinois, is being built by Energy Transfer Partners.

The Corps' approval allows the developer to bury the pipeline under the Missouri River a half-mile upstream of the tribe's reservation.

More: *The Gazette*

PSEG Files Opposition to Access Northeast with FERC

Public Service Enterprise Group has submitted a filing to FERC saying that a proposed natural gas pipeline expansion in New England would suppress wholesale prices in the energy market.

The company said the Access Northeast project, proposed by Spectra Energy and being subsidized by four New England states, is not driven by reliability needs, and the utilities that would own the pipeline would rarely use the gas. PSEG also compared it to a New Jersey plan to subsidize power plant construction in the state through the PJM capacity market, which was ruled unconstitutional by the Supreme Court as it infringed on FERC's jurisdiction.

Critics of the PennEast Pipeline in New Jersey, however, said PSEG's complaints could also apply to that project, which counts the company among its investors.

More: *NJ Spotlight*

Nuclear Industry to NRC: Streamline Review Processes

A number of industry executives called on the Nuclear Regulatory Commission to improve the efficiency of its review processes, especially when it comes to approving advanced reactors.

"Anything you can do through the regulatory process to assure that the advanced reactors can come online as soon as reasonably possible, it's going to be important not just for the United States, but for the world to meet this gap of increasing energy consumption," former FERC Commissioner Philip Moeller, now senior vice president at the Edison Electric Institute, said during a public stakeholder meeting in Rockville, Md.

The meeting was the first of its kind since 1998. NRC was directed to hold it by Sen. James Inhofe (R-Okla.), chair of the Senate Environment and Public Works Committee, which has oversight over the commission.

More: *Bloomberg BNA*

State Briefs

REGIONAL

Report Cites Emissions Drop in Nine-State RGGI

A new report by the Acadia Center says that carbon emissions in the nine-state Regional Greenhouse Gas Initiative compact have dropped 37% since the program began in 2008.

Part I of group's "RGGI Status Report" found that emissions have decreased in each of the last five years. Electricity prices across the region have decreased by 3.4% on average since RGGI took effect, while electricity prices in other states have increased by 7.2%, according to the report.

RGGI states have reduced emissions by 16% more than other states and seen 3.6% more economic growth since the initiative launched, the report adds.

More: *Acadia Center*

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STATE BRIEFS

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CALIFORNIA

Survey Shows Most Residents Support Climate Measures

A majority of likely voters say they are willing to pay more for electricity generated by renewable resources to help reduce global warming, according to a survey by the Public Policy Institute of California.

The survey also found that voters approve of the 10-year-old law requiring the state to reduce greenhouse gas emissions to 1990 levels by 2020 and would support additional efforts to curtail emissions. Still, more than half of those surveyed had never heard of the state's cap-and-trade program.

More: San Francisco Chronicle

Group Wants Waste Storage Included in San Onofre Review

A citizens group is asking the State Lands Commission to expand its environmental impact review of the San Onofre nuclear station's decommissioning to include plans for long-term storage of nuclear waste at the shorefront facility.

Southern California Edison's application to the agency makes no mention of its plans to indefinitely store spent fuel in containers located 100 feet from the beach. "It's just in a really bad spot," Ray Lutz, of Citizens Oversight, told the commission at its first public hearing on the decommissioning process. "And now we find out that that isn't even part of the review of this project."

A SoCalEd representative said the U.S. Nuclear Regulatory Commission has approved a license for a new storage facility at the site. The utility has proposed the EQR cover only two of four phases of the process; spent fuel storage is addressed in phase 3.

More: KPBS

COLORADO

Boulder Planning Board Approves Annexation Package

The City of Boulder's Planning Board voted unanimously last week to recommend the annexation of 16 city-adjacent properties, part of the city's effort to create its own municipal electric utility.

The bid to annex the properties, containing Xcel Energy facilities and customers, stems from a Public Utilities Commission ruling in November that partially rejected Boulder's municipalization application. The commission ruled that the city could not force Xcel to sell or share facilities that also served residents outside the city's limits.

The annexation package now goes before the City Council as the city prepares a new application for the PUC. However, Boulder and Xcel are also engaged in settlement negotiations that could bring an end to the city's plan, which was spurred by its desire to get all of its electricity from renewable resources by 2030.

More: Daily Camera

CONNECTICUT

Groups Criticize Natural Gas Conversion at Bridgeport Plant

Environmental groups criticized the $550 million conversion of a coal-fired power plant in Bridgeport to natural gas, saying it may actually be worse for the climate.

Environmental and community groups across New England said in a report that using natural gas until more renewable energy is available provides no gains and may actually worsen climate change. The report claims that the amount of methane leaked into the atmosphere from the extraction of natural gas is worse for the climate than burning coal.

PSEG Power has agreed to replace the coal-powered Unit 3 of Bridgeport Harbor station with a 485-MW gas-fired plant.

More: New Haven Register

KENTUCKY

IEFFA Recommends Shuttering Coal Plant

The Institute for Energy Economics and Financial Analysis is recommending that a coal-fired power plant in the state be closed as soon as possible.

In a study, the organization said both units at the Elmer Smith Station in Owensboro should be shut down because the plant is "long past its prime" and is a financial drain on Owensboro Municipal Utilities ratepayers. The report was completed at the request of the Ohio River Valley chapter of the Sierra Club's Beyond Coal Campaign.

"Tens of millions of dollars of new investment will be needed to keep the plant running and, using the utility's own analyses, shows that retail rates will increase by 20% by 2018 and 80% by 2025 if both units at Elmer Smith are not retired," IEEFA Director of Resource Planning David Schlissel said.

More: Messenger-Inquirer

EKPC Files with PSC to Build 60-Acre Solar Facility

East Kentucky Power Cooperative has submitted an application with the Public Service Commission for permission to build an 8.5-MW solar energy facility in Clark County.

The proposed $17.7 million project calls for the installation of 32,000 photovoltaic panels on 60 acres next to EKPC's offices.

A utility spokesperson said the solar facility would be funded through New Clean Energy Renewable Energy Bonds from the U.S. Energy Department, and retail customers will be able to receive monthly bill credits if they buy a 25-year, $460 license in exchange for a share of the facility's generating capacity.

More: The Winchester Sun

Continued on page 30

State Briefs

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MICHIGAN

State Energy Agency Backs ATC Plan for Removal of SSR

The state Agency for Energy said it backs a plan from American Transmission Co. to reconfigure its system in the Upper Peninsula, which would eliminate payments to a 60-year-old coal-fired power plant that it says costs ratepayers $7.3 million each year.

The agency, in a letter to MISO, endorsed ATC's plan, which would also revise its system operating guide for the UP. The plan would eliminate the need for a system support resource (SSR) agreement to the White Pine power plant.

UP ratepayers have been making SSR payments for the operation of White Pine Unit 1 for more than two years and would be slated to continue payments until 2020. The state has challenged several other SSR agreements, which provide for payments to generators to continue running for reliability.

More: WJMN

NEBRASKA

Saline County Approves Aksamit's 74-MW Wind Farm

The Saline County Commission granted Aksamit Resource Management's request to build a 74-MW wind farm southwest of Lincoln.

Construction is expected to begin after harvest this fall, with the turbines operational by Nov. 1, 2017. Aksamit is in negotiations to sell the wind farm's power, but the company has declined to say with whom.

It is the first of three wind energy projects Aksamit plans for the state. The company plans to spend about $440 million on a nearby 300-MW farm and a 76-MW project.

More: Lincoln Journal Star

NEVADA

NVE Pushes Net Metering Grandfathering Proposal

NV Energy last week asked the Public Utilities Commission to allow some rooftop solar customers to receive the more generous net metering rates that were phased out at the start of the year.

Under the proposed change, customers who installed their panels or receive application approvals before the end of 2015 would be eligible to get compensated under the original net metering terms for a period of 20 years.

The utility's request to grandfather some projects under the old rules comes as the state Supreme Court prepares to hear arguments over whether to allow a ballot initiative that would restore the original rates to all current and future customers.

More: Las Vegas Review-Journal

NORTH DAKOTA

Politicos, Regulators Fear More Coal Plants to Close

Great River Energy's announcement that it would close a coal-fired power plant in the next year is just the first blow against the state's coal industry, warned a congressman and a state utility regulator.

"I don't think we can presume this is an outlier," said U.S. Rep. Kevin Cramer, a former state utility regulator and an energy adviser to presidential candidate Donald Trump. He said he feared what has happened in the Appalachian region, where local economies have been hurt by the coal plant closures, will happen in the state.

Public Service Commissioner Randy Christmann acknowledged that low natural gas prices contributed to Great River's decision to close its plant, but he pointed to competition from "heavily subsidized" wind energy. "I just think we've gotten to a point where they're overly subsidized," Christmann said.

More: Grand Forks Herald

TEXAS

EPE Kills $11 Charge on Rooftop Solar Customers

El Paso Electric will withdraw its proposal to charge customers with rooftop solar panels an additional $11/month under a settlement with a coalition of solar-energy companies and environmental advocates and the city of El Paso. The agreement was filed with the Public Utility Commission.

EPE withdrew the proposal after almost a year of claiming solar customers were more expensive to service and should be subject to an additional fee. Approval of the agreement by the PUC is likely to happen in the next couple months.

The battle between consumer advocates and the investor-owned utility began last year when EPE filed a rate case seeking to cover $1.3 billion in infrastructure investments. Among the proposals was an additional charge for the more than 1,770 Texas solar power users in the company's service area.

More: The Texas Observer

WYOMING

State, Japanese Partner to Research Clean-Coal Technology

Gov. Matt Mead signed a memorandum of understanding last week with the president of the Japan Coal Energy Center, calling for cooperation between the consortium of Japanese companies and state experts in researching clean-coal technology.

Mead

Mead says he expects to see a conference in the state within a year that would allow Japanese researchers to work with researchers from the University of Wyoming School of Energy Resources on coal issues. The state has been pushing to try to gain access to ports in the Pacific Northwest to export coal to Asia.

More: The Associated Press

Massachusetts Bill Boosts Offshore Wind, Canadian Hydro

Continued from page 1

cause it has not won a competitive lease auction from the federal government.

First Mover

In January 2015, the U.S. Bureau of Ocean Energy Management awarded offshore leases to RES America Developments (lease area OCS-A 0500 for 187,523 acres) and Offshore MW (lease area OCS-A 0501 for 166,886 acres) in the Massachusetts Wind Energy Area, which starts about 12 nautical miles offshore. Last June, BOEM approved the assignment of RES America's lease to DONG Energy Massachusetts.

BOEM said the area leased could support approximately 2 GW of wind generation.

Thomas Brostrøm, general manager of North America for DONG Energy Wind Power, said the legislation "will allow the creation of a viable offshore wind energy industry here in Massachusetts."

The company said it plans to install capacity of up to 1 GW in the form of what it is calling Bay State Wind, a project it said will create 1,000 new jobs in Massachusetts during construction and approximately 100 new jobs to support the wind farm during its life.

"With world-class wind speeds and ideal water depths of between 130-165 feet, Massachusetts will be able to garner the economic benefits and supply chain development of being the first mover to site utility-scale offshore wind energy on the East Coast of the United States," the company said.

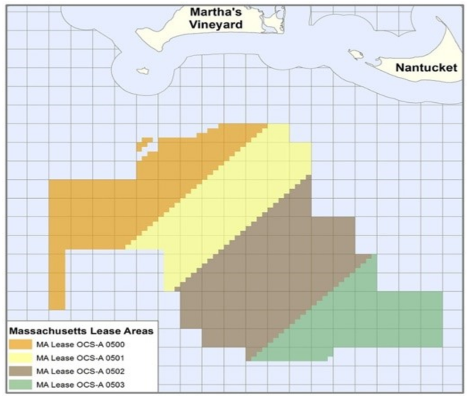
DONG Energy, based in Denmark, operates 19 offshore wind projects totaling more than 3 GW with another 3 GW under construction.

Offshore MW, which is partnering with the nonprofit Vineyard Power Cooperative on its project, could not be reached for comment.

Other Provisions

In addition to jumpstarting offshore wind, the Massachusetts bill:

- Promotes energy storage, authorizing the Department of Energy Resources to develop procurement targets and incentives for utilities, households and businesses;
- Requires utilities to fix their most serious gas leaks; and
- Expands energy efficiency and clean energy financing options for commercial customers under the Property Assessed Clean Energy program.



Massachusetts Wind Energy Area *Source: BOEM*

Lawmakers rejected the Senate's proposed increase in the RPS, incentives for electric vehicle adoption and a prohibition of the so-called "pipeline tax," which would allow electric distribution companies to assess ratepayers for construction of the extra capacity needed by natural gas pipeline owners to supply power plants.

Power plant owners and marketers oppose the policy, but state officials say the capacity is needed to mitigate price spikes caused by tight supplies.

The state Department of Public Utilities has already determined that such supply contracts are allowed under existing state law. An LNG supplier and an environmental group, supported by the Massachusetts attorney general, have challenged that interpretation. A ruling is expected soon from the state's Supreme Judicial Court. (See *More Pipelines for New England: 'Gold-plating' or Necessity?*)

The energy legislation was one of several bills that required last-minute action at the Capitol before the July 31 deadline, after the legislative calendar was cleared for the Republican and Democratic national conventions.

Both houses had agreed that Massachusetts needed to significantly increase the amount of clean energy used to comply with its Global Warming Solutions Act, passed in 2008. Nuclear and coal-fired generation have been closing in recent years, and ISO-NE says the region is facing tight energy supplies. (See *Massachusetts Clean Power Bill Hit from All Sides*.)

Gov. Charlie Baker, a Republican, had opposed the Senate's inclusion of Cape Wind and the "pipeline tax" prohibition. The governor issued a statement Monday thanking lawmakers for completing the energy bill and other legislation before the deadline.

"As our administration carefully reviews all of the legislation that lawmakers worked diligently to reach consensus on, I will continue to work across the aisle with our partners in the legislature to make Massachusetts a better place," Baker said.

Enviros Supportive; Generators Dismayed

The New England Power Generators Association criticized the bill, saying it would "dramatically increase costs for consumers and undermine billions of dollars in energy investments" in the state.

"This energy bill represents the single biggest step away from a competitive electricity market ever taken in New England," NEPGA President Dan Dolan said. "Power plant owners in Massachusetts will now be barred from competing for nearly 60% of the commonwealth's electricity market. Instead, consumers will be forced to pay for huge amounts of power at above-market prices, eliminating opportunities for innovation and cost containment."

Members of the Alliance for Clean Energy Solutions, a coalition of clean energy companies, environmentalists and consumer representatives, had a different perspective.

"This bill is a huge step on the path to a clean energy future," said Peter Shattuck, Massachusetts director of the Acadia Center. "The legislation solidifies the commonwealth's leadership in reducing carbon pollution and will help reduce our growing over-reliance on natural gas."

Janet Gail Besser, executive vice president of the Northeast Clean Energy Council, said the bill "will not only accelerate the deployment of clean energy, but will also serve to accelerate our economy by providing a stable policy framework for investors and developers of clean energy."

Emily Norton, director of the Sierra Club's Massachusetts chapter, praised the legislature for its boost to offshore wind and "for forcing utilities to fix methane leaks that are warming our planet, killing trees, jeopardizing safety and wasting consumer dollars."

"However the bill does not go far enough in terms of transitioning us to a clean energy economy and a transportation sector powered by clean electricity rather than petroleum," she continued. "It is also very disappointing … in spite of a unanimous Senate vote to prohibit a pipeline tax, to see that language missing from the final version. We look forward to making further gains toward climate justice in the next legislative session."

NARUC Summer Meetings 2016

NARUC Panel Considers Smart Grid's Accomplishments, Regulatory Responses

By Rich Heidorn Jr.

From left to right: Alex Laskey, Opower; Tom Healy, EnerNOC; Eric Dresselhuys, Silver Spring Networks; Linda Sullivan, American Water; David Kolata, Citizens Utility Board; and moderator Brien Sheahan, Illinois Commerce Commissioner. © *RTO Insider*

NASHVILLE, Tenn. — There are more than 50 million smart meters and more than 1,000 phasor measurement units (PMUs) deployed in the U.S., the product of a rollout funded in part by federal Recovery Act spending following the 2008 financial crisis.

What have we gotten for our money?

High bill alerts, proactive service calls, peak shaving abilities and self-healing transmission, among other things, a panel of technology executives told the National Association of Regulatory Utility Commissioners summer conference last week.

Now, with smart grid technologies more widely deployed, it is slower-moving regulators and utility procurement practices that are hindering innovation, Silver Spring Networks' **Eric Dresselhuys** said.

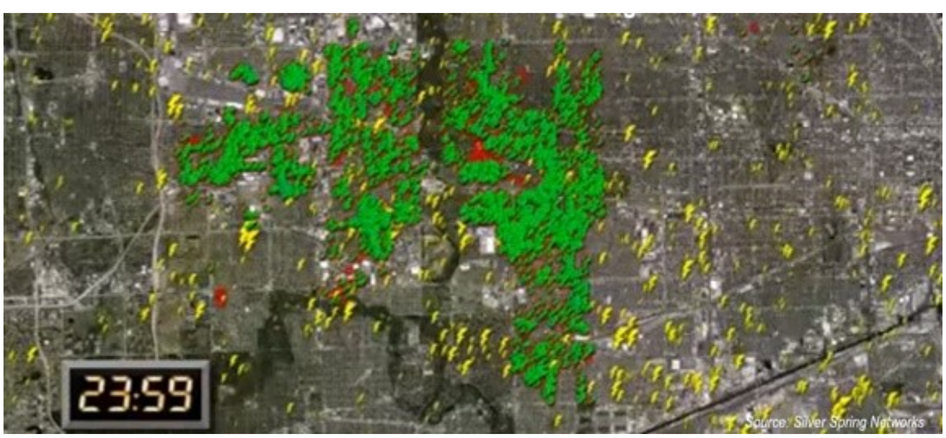
"If you've got energy technology cycles that are happening in 12-, 18- and 24-month cycles and utility adoption cycles and regulatory proceedings that are happening in the three- to five-year range, ultimately what you do … is by the time you make a decision, that decision is outdated, because [technologies] have moved on," said Dresselhuys, executive vice president of global development for the company, which provides smart grid networking platforms.

High Bill Alerts

Alex Laskey, president and founder of Opower, said utilities have reported a 20% drop in customer calls regarding high bills following a smart meter-enabled program that alerts ratepayers of spikes in energy use. Opower provides "customer engagement" platforms for utilities, a niche growing so fast that technology giant Oracle agreed in May to buy the company.

"Not unlike those fraud detection alerts [used by credit card companies], we alert customers on behalf of their utility via text or email or a phone call. … 'You're on track for a high bill. It's only eight days into the month, but you're on track for a bill that's 30% higher than your typical bill this time of year and here are some things you ought to do to try and reduce your usage,'" Laskey explained.

"Customers like it because instead of getting [a large] bill at the end of the month when it's too late, you're being alerted in advance that something is amuck and you can make a change," he continued. "Particularly for low-income customers — for whom electricity represents 8 to 10% of their income — the ability to give them predictability and transparency on what their costs are going to be is critical."



Commonwealth Edison's self-healing grid performs in a thunder storm, with reclosers restoring power within seconds or minutes.
Yellow pins: Lightning strikes. Red pins: Smart meters that have lost power. Green pins: Smart meter power restored.
Source: Silver Spring Networks

Shaving the Peak

Laskey also cited Baltimore Gas and Electric's peak time rebate tariff, which rewards customers for saving energy on the hottest days.

"PJM has measured more than a 15% reduction now at peak for BGE," Laskey said. "This is just by giving customers better information and a financial incentive.

"You can do that across the country. [Rocky Mountain Institute] estimates $60 billion a year in customer benefits and none of it is possible without regulatory incentives and reform … but on the same hand it can't be enabled without reliable software."

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NARUC Panel Considers Smart Grid's Accomplishments, Regulatory Responses

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The Value of Power Quality

Commonwealth Edison is using big data analysis to identify areas on its grid where customers are receiving voltages below the nominal 240 V, allowing it to "drop in better voltage regulation," Dresselhuys said.

"When you combine this with things like conservation voltage reduction and other advanced analytics that are being done, the amount of optimization that can be built into the grid on a daily basis is pretty dramatic."

But Dresselhuys said "the ratemaking and procurement processes within utilities really struggle with the idea of futures or what is the option value that comes from technology."

"What's the value of good consistent power quality? The utility doesn't make more money on that and they didn't show savings by doing that. And so it doesn't get put into the rate case and if you don't put it into the rate case, it doesn't make the technical requirements because you can say, 'Well you're gold-plating the system,'" Dresselhuys said. "So one of the things we have to figure out is, if we're implementing techs that we expect to last for five, 10, 15 or 20 years, how can we make sure that we're building platforms … that will continue to add value to consumers over time?"

Proactive Service Calls

Dresselhuys recalled the beginning of smart meter deployment. "Ten years ago people said, 'Why would we ever need hourly data?' Now people are cranking that up to five-minute data and one-minute data in some cases."

He said one Silver Spring customer has been able to use the increasingly granular data to change its maintenance procedures from the "break-fix mentality of 'let's just wait until there's an outage and we'll go there and fix it.'"

The utility, which serves a seaside location, can identify momentary outages at customer locations, an indication that their service drop — the wires running from the utility pole to the house — has suffered corrosion.

"Worst-case scenario, it starts a fire. The best-case scenario, they just lose power," Dresselhuys explained. "The customer wouldn't even notice this because it's just maybe a flicker if anything."

The diagnostics allow the utility to schedule proactive service calls to replace the defective wiring.

Financial Reporting

Tim Healy, CEO and co-founder of demand response provider EnerNOC, said the increase in data is crucial to large customers, such as the 700 commercial real estate firms that are now reporting their Global Real Estate Sustainability Benchmark (GRESB) scores on more than a trillion dollars' worth of assets.

"It is one of the key metrics that investors are using in order to make investments in the real estate sector," Healy said. "What we're seeing with our customers is they have an acute need that goes not just right to the bottom line but it goes to their access to capital to run their businesses. The information technology and the needs of the financial reporting organization need to intersect more than ever before."

Dave Kolata, executive director of the Citizens Utility Board in Illinois, said consumer advocates are having to become more tech savvy to determine the costs and benefits of new technologies and avoid stranded costs resulting from the replacement of systems that have not been fully depreciated.

"Traditionally, IT investment has been something of a black box," he said. "It's not something that … we have much expertise in."

NARUC Summer Meetings 2016

Little Love for PJM in Capacity Market Debate

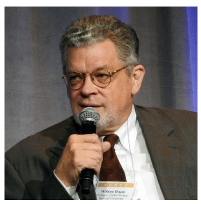
Nuclear Subsidies also Criticized

By Rich Heidorn Jr.

From left to right: Sarah Novosel, Michael Haugh, Allison Clements, Jay Morrison, William Hogan and Travis Kavulla. *© RTO Insider*

NASHVILLE, Tenn. — PJM's Capacity Performance rules got little love last week during a panel discussion on the role of states versus markets in procuring electric generation.

Other Eastern RTO capacity markets and New York's planned nuclear subsidies also came under fire in a discussion at the National Association of Regulatory Utility Commissioners summer conference.



Economist **William Hogan**, of the Harvard Kennedy School, and Allison Clements, a Natural Resources Defense Council representative to the Sustainable FERC Project, led the criticism of PJM's Capacity Performance rules.

Clements said the environmental community does not have a preference between wholesale markets and bilateral trading. "But if [markets are] going to exist, we want to make sure that the rules are fair so that clean energy resources can compete to provide services," she said.

Aside from FERC Order 745, which helped demand response resources enter the wholesale markets, she said, "we haven't been that successful, and we've come to this point where the energy/capacity market construct, at least in the Eastern Interconnect RTOs … [is] broken."

Clements said PJM's Capacity Performance rules, which favor baseload generation available 24 hours a day year-round, "locks in this traditional, outdated resource mix view" that favors nuclear energy over renewables and DR, a case NRDC and other environmental groups made last month in asking the D.C. Circuit Court of Appeals to review FERC's approval of PJM's rules. (See *Clean Energy Advocates Appeal FERC's Capacity Performance Rulings*.)

While CP rules allow summer and winter resources to aggregate a single capacity offer, no aggregate offers were submitted in the first Base Residual Auction with CP for delivery year 2018/19. In the second auction under the new rules in May, only 6% of cleared DR resources qualified as CP, compared with 9% of wind and one-tenth of 1% of solar.

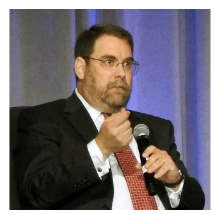
"Because renewables can't provide baseload Capacity Performance … the capacity they do provide doesn't get counted, which means that your state policy to encourage clean energy that your customers are paying for isn't getting full value," Clements said.

Hogan also was critical of CP and of FERC's oversight. He said the commission needs to ask the question: "'Are the changes we're making in market design going in the right direction?' And when it's not, to stand up and face it squarely and don't succumb to double talk."

PJM's CP penalty mechanism means generators could face penalties of $5,000/MWh for shortfalls while the demand side will be seeing prices that are only $500/MWh, Hogan said.

"This can't make sense," he said. "You should be able to test these designs against [a] Platonic vision … and where there's a dramatic difference like that you should be able to ask 'Why are we doing this? Why are we sending signals to the generators and not to the load when we get into critical capacity situations?'"

Clements said it's not necessary to abandon capacity markets and go to shortage pricing, as in ERCOT. "I think there's something in between there," she said, praising the "flexibility products" being offered in CAISO and MISO.



Jay Morrison, vice president of regulatory issues for the National Rural Electric Cooperative Association, also contended that RTO capacity markets aren't working.

"Where's the tangible evidence that they're failing in their mission?" asked panel moderator and NARUC President Travis Kavulla, noting the new resources that have cleared PJM and other capacity markets.

"My litigation budget," Morrison quipped. "I could save a lot of money if these markets were working properly."

But Morrison also challenged Hogan. "There's no Platonic ideal of a market out there," he said. "Markets are designed for specific purposes. These markets should be designed to meet the needs that the consumers express through the utilities that serve them, through their politically elected or appointed officials.

"The market should be designed to meet the needs that the consumers want," he continued. "The consumer shouldn't be asked to buy the product that the market says is the right product. We need to remember which is the dog and which is the tail."

Morrison said states have intervened — sometimes running afoul of FERC jurisdiction — "because there are important values

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Little Love for PJM in Capacity Market Debate

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that they are trying to pursue … that aren't important to the market operators and aren't incorporated into the market design."

"Yes there are new resources [from capacity markets], but are they the right resources?" Morrison asked. "Yes, there are new resources, but are some of the people investing in them risking that they're going to pay twice? Both for the resource in which they're investing and the one that the market operator says they're supposed to buy."

RTOs have developed valuable new products for managing system operations but have not responded with the environmental or risk management products sought by consumers and state policymakers, he said. "Those are the kind of products for which bilateral markets are ideally suited," he said. "And so long as we have the minimum offer price rule [and] buyer-side mitigation, we have trouble accessing those resources."

The only panelists to offer much support for RTO capacity markets were **Michael Haugh**, assistant director of analytics for the Ohio Consumers' Counsel, and Sarah Novosel, senior vice president and managing counsel for Calpine.

Haugh said PJM's markets have brought new generation to serve Ohio and encourages sharing of resources among states, which reduces costs.

Novosel said her company would prefer capacity markets in all regions. She reserved her criticism for state interventions, such as proposals in Illinois, Connecticut, New Jersey and New York to subsidize nuclear plants. She said New York's zero-emission credit program for its upstate nuclear fleet is discriminatory, will hurt markets and intrudes on federal jurisdiction, in violation of the U.S. Supreme Court's ruling in *Hughes v. Talen*. (See related story, *New York Adopts Clean Energy Standard, Nuclear Subsidy*, p.1.)

"We're troubled by all of these proposals because all of them, we feel, are going to undermine the wholesale markets, which competitive generators rely on for our revenue," she said. "And once you start to pull the string and start to unravel these wholesale markets, you're going to end up with having other generators who rely on the wholesale market needing a subsidy or long-term contract in order for them to also receive sufficient revenue to continue operations. … And by entering long-term contracts, you're putting the risk back onto the ratepayers."

Novosel acknowledged that "we don't have any answers — yet." But she said she is encouraged by the efforts being taken by RTOs to address the challenges. She cited PJM's white paper in May and its Aug. 18 Grid 20/20 forum on public policy goals and market efficiency, and the New England Power Pool's planned stakeholder meeting on Aug. 11 on how to preserve markets while also reducing states' carbon footprints. "We've got a lot of smart people in this industry. We can come together and come up with a solution that works," she insisted.

The simplest fix for the plight of nuclear generation and the desire for less polluting resources, the panel agreed, was to internalize the cost of carbon into the markets — a no-brainer to economists but a nonstarter for many politicians.

"I just don't believe that" enacting a carbon tax is impossible, Hogan said, noting that he heard similar warnings before ERCOT's move to scarcity pricing.

"I've been involved in lots of things that were 'politically impossible' when we first started talking about them," he said. "And now they're old hat and conventional wisdom."

Economist Craig Pirrong, of the University of Houston's Bauer College of Business (left); Tim Sherwood, vice president of gas supply operations for Southern Company Gas (formerly AGL Resources) (center); and Orlando Alvarez, CEO of BP Energy (right), discussed hedging and long-term contracting. *© RTO Insider*

NARUC Summer Meetings 2016

Cybersecurity Rules Urged for Distribution Companies

By Rich Heidorn Jr.

NASHVILLE, Tenn. — Regulators from Connecticut and New Jersey last week urged their colleagues to join them in developing cybersecurity rules for electric distribution companies.

"Get in motion. Get started," **Arthur House**, chairman of the Connecticut Public Utilities Regulatory Authority, told the National Association of Regulatory Utility Commissioners summer conference. "We have to attack it. It's too important not to."

In April, the state released a Cybersecurity Action Plan, which calls for a voluntary oversight program in which utilities would meet annually with state officials to report on their cyber defense programs, experiences over the prior year dealing with cyber threats and corrective measures they planned.

PURA said it will consider adding reviews by "objective, third-party assessors." The New Jersey Board of Public Utilities issued more prescriptive rules in March requiring senior officers of distribution companies to certify their cyber protection plans, BPU President **Richard Mroz** said. The rules apply to natural gas, water and wastewater utilities, in addition to electric distribution companies.

The BPU requires the companies to define responsibilities for cyber risk management activities and establish plans for identifying and mitigating risks to critical systems. It also requires companies to provide cybersecurity awareness training and to report cyber incidents and suspicious activity to the agency.

House said it's understandable that state regulators are reluctant to take on the issue. "There's just too much work in this job already. We already have too much work to do," he said.

NERC's mandatory reliability standards cover only the Bulk Electric System, generally defined as transmission lines operating at 100 kV and above. (See *FERC Refines Bulk Electric System Definition*.)

Nevertheless, some state regulators see cybersecurity as the exclusive job of the federal government, House said.

Air Gap?

House said he was dismayed to hear Exelon CEO Chris Crane say earlier in the NARUC conference that part of his company's defense is an "air gap" between Internet-connected computers and the supervisory control and data acquisition (SCADA) system.

"I've never met a federal official who believes the air gap exists. We stopped hearing about it from private sector officials in utilities two years ago at least," House said. "It certainly is an outdated reference to a rather discredited concept."

On July 21, however, FERC issued a Notice of Inquiry seeking comment on the Critical Infrastructure Protection reliability standards for transmission control centers and whether the commission should require the separation of the Internet and industrial control systems (RM16-18). The notice also asked for input on application "whitelisting" practices to prevent unauthorized programs from running in control centers. (See *FERC Orders NERC to Develop 'Flexible' Supply Chain Standard*.)

House also disagreed with Crane's description of the level of cooperation between government and industry. Crane, a member of the Electricity Subsector Coordinating Council, a liaison between the federal government and the power sector, said communication between the government and industry on cyber threats has improved greatly.

"It's become much better in the last couple of years, having everybody around the table" — U.S. Cyber Command, the FBI and the departments of Defense, Energy and Homeland Security — "really working to communicate across the table much better. The silos are breaking down and the information is flowing."

House disagreed.

"They're not sitting at the same table. They're not talking the same language," he said. "We have goodwill [and] occasional cooperation. But we do not have an adequate defense system or adequate recovery" plans.

"There is a huge gap," he continued. "I think we'll have a partial compliance until we have an attack and then you'll get mandatory standards" for EDCs.

Defense in Depth

FERC Commissioner **Cheryl LaFleur** said distribution companies and their regulators don't need to wait for formal requirements. "There's a lot that can be done at the distribution level without mandatory standards," she said, noting that many distribution utilities are NERC registrants because of their transmission assets. "It's not as if any of them are unaware of cyber challenges."

LaFleur said the NERC standards approved by FERC rely on "defense in depth," including perimeter security, virus screening and other measures. Every successful attack, she said, is the result of multiple failures.

Referring to the cyberattack on three EDCs in Ukraine, LaFleur said, "Many things could have stopped it." (See *How a 'Phantom Mouse' and Weaponized Excel Files Brought Down Ukraine's Grid*.)

On July 21, LaFleur dissented on a FERC order directing NERC to develop a reliability standard for supply chain management, saying the order failed to provide enough guidance and should have been delayed to allow more study (RM15-14-002).

Texas Public Utility Commissioner Ken Anderson said he worried the rule could create a "false sense of security."

In 2011, he noted, Boeing and the Navy found that the ice detection system on a new P-8 Poseidon, a plane designed for long-range anti-submarine and anti-surface warfare and intelligence missions, was defective because it contained counterfeit components sold by a Chinese subcontractor.

"If the Pentagon — that actually has access to the intelligence — if they can't catch the defective subcomponents going into a military weapons system … how the heck can a utility know what's in that chain?" he asked.

From left to right: Mroz, House, LaFleur and Washington Utilities and Transportation Commissioner Phil Jones
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NARUC Summer Meetings 2016

Net Metering Debate Continues in NARUC Session

By Rich Heidorn Jr.

NASHVILLE, Tenn. — Present and former regulators debated the costs and benefits of rooftop solar and the pros and cons of net metering in a spirited discussion at the National Association of Regulatory Utility Commissioners summer conference last week.

Charles Cicchetti, former chair of the Wisconsin Public Service Commission, and former Ohio Public Utilities Commissioner Ashley Brown led off the debate.

Cicchetti, a member of Pacific Economics Group and former economics professor at the University of Southern California, said regulators' moves to curtail or reduce net metering payments and introduce new demand charges "greatly cut into the benefits that customers who installed rooftop solar expect to earn and use to pay for those systems."

Cicchetti said regulators should require "vetted … neutral studies" to determine the costs imposed by solar customers and compare them with the benefits they provide.

"When you do that you'll probably come away with the conclusion that, if anything, the extra costs that are being imposed by rooftop solar [are] far less than the extra benefits both in utility savings and societal benefits," he said.

He said that time-of-use tariffs are more fair than demand changes, which he called "a blunt instrument."

"If [rooftop solar customers] take electricity during expensive times, they should pay more. But they should also save more when they reduce electricity — as most of them do — during the time that those systems are operating."

Brown, of the Harvard Electricity Policy Group, disagreed, saying solar customers under net metering are not paying their fair share of the system's fixed costs.

The value of solar studies is incredibly subjective, Brown said. "Many states have done them; many interest groups have had them done and the findings are all over the map," with some finding the value of solar is double the retail price and others finding a negative value. "Neither of those cases could possibly be true.

"Several things are always missing from these studies," Brown continued. "One is, every single one of these values can be obtained from other sources. So why aren't we disciplining the price we pay for those values by putting it into a marketplace with other sources? And many of these values are provided by other forms of generation who aren't compensated for it because we don't pay anybody based on value. We pay them based on market or we pay them based on cost."

Nevada Public Utilities Commissioner David Noble spoke about the state's bruising net metering battle last year, when the PUC conducted a ratemaking in response to a legislative mandate that rooftop solar result in "no unreasonable cost shifts."

Noble said the commission was vilified by solar energy providers even though it rejected demand charges, implemented optional time-of-use rates and ordered a phase-in of "value-based" rates for excess energy.

"The rooftop solar companies decided to take an approach … that there should be no change from retail rates," he said. "When you take an all-or-nothing approach, there's a possibility that you're going to lose. And that's exactly what happened because they put on an inferior case.

"The CEO of SolarCity was claiming that he literally had a gun to his head and the commission was in the back pocket of" NV Energy, he said.

Solar companies bused hundreds of protesters to PUC headquarters, some of them exercising their open-carry rights to travel with guns, Noble said. There they attempted to alarm consumers by claiming utility rates would increase by 3% annually for the next 20 years.

"We haven't had 3% increases year-over-year for any longer than three years," he said. "In fact, over the last six years … rates have been flat in southern Nevada and they've gone down 20% in northern Nevada."

Beverly Heydinger, chair of the Minnesota Public Utilities Commission, said the focus on net metering and rooftop solar is myopic, and that policymakers should also consider storage, electric vehicles and other emerging technologies.

"We're not planning for today. We're trying to develop a flexible enough template that we can use it and adapt as the times are changing," she said.

The Solar Energy Industries Association held a panel discussion on the community solar market. From left is moderator Sean Gallagher, SEIA vice president of state affairs; Hawaii Public Utilities Commissioner Lorraine Akiba; Jeff Hudson, vice president of business development for the Clean Energy Collective; and Danny Kassis, vice president of customer relations and renewables for South Carolina Electric & Gas. *Source: RTO Insider*

NARUC Summer Meetings 2016

Challenges to Building Infrastructure

NASHVILLE, Tenn. — Regulators and utility officials commiserated over the difficulty in overcoming public opposition to large energy infrastructure projects during a panel discussion at the National Association of Regulatory Utility Commissioners summer conference last week. About 1,000 people attended.

Iowa Utilities Board member **Libby Jacobs**, who moderated the session, said she had become the target of vitriol following her vote in June approving the Dakota Access Pipeline, which will carry crude oil from North Dakota's Bakken field through South Dakota and Iowa to Illinois. The week before the NARUC meeting, an activist group staged a street theater performance outside IUB offices called "In Bed with the Bakken," in which one protester portrayed Gov. Terry Branstad bottle-feeding an oil pipe.

"I'm also very familiar with the anti-infrastructure protesters," offered FERC Commissioner Cheryl LaFleur from the audience, referring to the monthly protests at FERC open meetings.

Opposition to infrastructure projects has been a challenge "since I've been in the industry," she continued. "But I sense something different happening.

"I'm a little concerned … with the growing thought out there that maybe we don't need any infrastructure at all," LaFleur said. "'We're just going to close what we have and replace it with everything distributed.'"

Jacobs, a former corporate communications executive, said protesters have benefited from social media as an organizing tool.

Aakash Chandarana, regional vice president of rates and regulatory affairs for Xcel Energy's Northern States Power, said utilities need to do a better job of educating their customers.

"Often times we as a utility are trying to talk to our customers at the most intense period in our relationship — either through storms or during a rate case or something like that. … We have to approach our customers at a period of time where maybe there isn't as much emotion."

Robert Kenney, vice president of state regulatory relations for Pacific Gas and Electric, agreed. "I'm not sure that utilities or regulators have done [a good] job in helping customers understand why certain investments need to be made," he said.

He lamented the utility's decision, announced in June, to retire the Diablo Canyon nuclear plant when its current operating licenses expire in 2024 and 2025, noting it "has been a source of greenhouse gas-free energy for the last 30-some odd years." (See PG&E to Shut Down Diablo Canyon, California's Last Nuclear Plant.)

"The political climate in California was such that being able to relicense that beyond 2024 and 2025 made it a huge challenge," Kenney continued. "I say that as an example of the fact that we have technologies that will allow us to meet climate goals but then you have conflicting political goals that prohibit the running of nuclear generating facilities."

Commercial Customers Will Go it Alone to Meet Sustainability Goals

The Critical Consumer Issues Forum released its latest report last week with a panel discussion featuring (left to right) John Evans, Pennsylvania Office of Small Business Advocate; Commissioner Nick Wagner, Iowa Utilities Board; Katrina McMurrian, CCIF executive director; Bob Nelson, Montana Consumer Counsel and president of the National Association of Utility Consumer Advocates; Barbara Lockwood, vice president of regulation at Arizona Public Service; and Georgia Public Service Commissioner Stan Wise. *© RTO Insider*

Commercial customers would like utilities' help in meeting their sustainability goals but "will pursue their goals with or without" them, according to the Critical Consumer Issues Forum's latest report released last week.

More than 80 state regulators, consumer advocates and utility representatives took part in meetings that resulted in the report, developing "consensus principles," such as providing flexibility to consumers seeking new technologies and products while protecting nonparticipating consumers from cost shifts.

To be responsive to customers, Arizona Public Service will initiate some innovative projects without getting regulatory approval first, said Barbara Lockwood, vice president of regulation.

"We have taken the approach that there are some projects that we're going to embark on and we're not going to ask the commission [in advance]. We're going to go do it and then we're going to ask for recovery of those costs. We're taking some risk that we never took in the past," she said.

Lockwood cited a 25-MW microgrid the utility is building with the U.S. Navy at Marine Corps Air Station Yuma. The microgrid's diesel generator can provide peak power to APS customers during normal operating conditions and is large enough to power all base operations during a grid disturbance. "We didn't seek preapproval for that project," Lockwood said. "It was important to move quickly."

NARUC Summer Meetings 2016

Exelon CEO Talks Capital Allocations, New Products

NARUC President **Travis Kavulla** conducted an interview with Exelon CEO **Chris Crane** that touched on subjects from capital allocations and new utility products to the struggles of its nuclear generation fleet and cybersecurity.

Kavulla asked Crane whether Exelon, which now operates in five states and D.C. following its acquisition of Pepco Holdings Inc., favors states with higher returns on equity in determining where to allocate capital.

Crane said each of the company's six utilities maintains its own balance sheet and cash flow and that the company makes investments based on reliability requirements.

"It does at times require equity infusion from the parent. PHI right now, and for the next five years, will have equity infusions … on an annual basis.

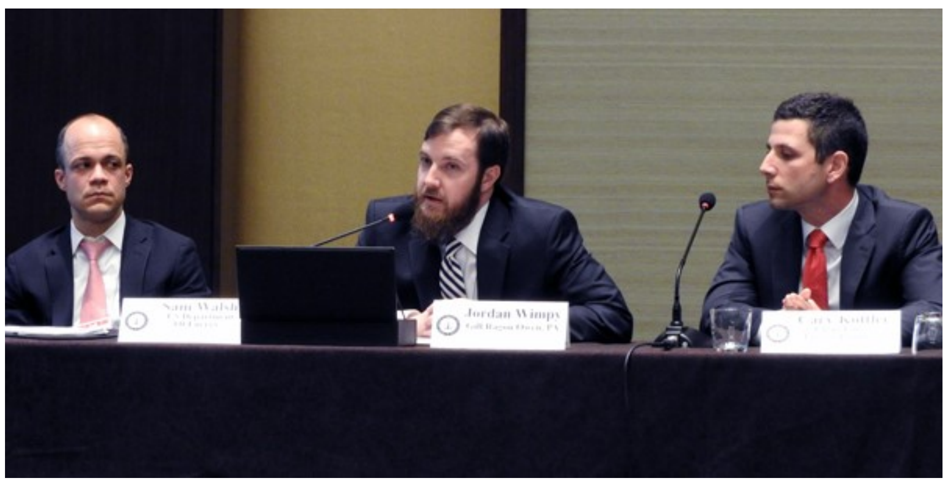
"We don't find that as a conflict," Crane said. "We've never had to make a decision that a dollar goes into one jurisdiction versus another … there is enough capital and our balance sheets are strong."

Crane said Exelon's decisions on what "utility of the future" products to offer is based on "understanding what is a trend and what is a fad."

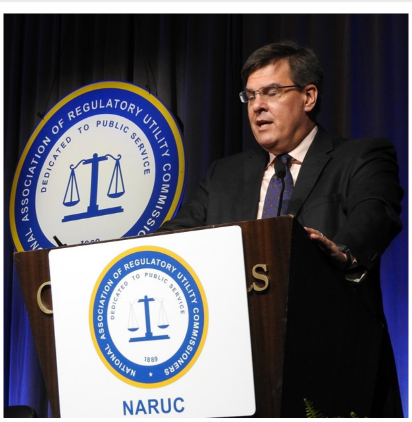
Federal-State Battle over Plains & Eastern Transmission Line

Jordan Wimpy, an attorney representing landowners opposed to Clean Line Energy Partners' Plains & Eastern transmission line, said he is likely to file a court challenge seeking to block the Department of Energy's record of decision supporting the project. "We are prepared to file and we are moving in that direction," Wimpy said.

The department said in March that it would partner with Clean Line on the $2.5 billion, 700-mile HVDC transmission project, which would deliver 4,000 MW of wind power from the Oklahoma Panhandle to MISO and the Tennessee Valley Authority. The department acted after Clean Line was unable to win approval from Arkansas regulators. (See DOE Agrees to Join Clean Line's Plains & Eastern Project.)



Jordan Wimpy (center) speaks as Sam Walsh, deputy general counsel for the Energy Department (left) and Clean Line Energy General Counsel Cary Kottler (right) listen. © *RTO Insider*



Who Will Do the Work?

Mark Bridgers, a principal with Continuum Capital, a Raleigh, N.C., investment banking advisory firm, presented a forecast indicating utilities need to add 50,000 new transmission and distribution workers. By 2018, Bridgers said, all of New England, much of the Mid-Atlantic and several Western and Midwest states will face shortages in T&D workers.

Bridgers gave a plug to the Underground Construction Workforce Alliance, which is building a coalition of industry associations, unions, suppliers, engineers, contractors and utilities to develop training programs and regulatory approaches to develop the workforce required.