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

ISSN 2377-8016 : Volume 2016/Issue 42 November 1, 2016

Price Tag on Tx Needed to Meet California 50% RPS: $5B?

By Robert Mullin

Meeting California's 50% by 2030 renew-able standard could require up to $5 billion or more in transmission upgrades, according to report released this week by the California Energy Commission.

The report outlines what transmission projects the state must build or upgrade to connect load zones with areas identified as having the potential to provide more than 40,000 MW of new renewable capacity.

The study is a product of the Transmission Technical Input Group (TTIG) convened under the Renewable Energy Transmission Initiative (RETI), a collaboration that includes CAISO, the state's major municipal and investor-owned utilities, the Western Area Power Administration and the California Natural Resources Agency.

RETI has determined that California will need an additional 25 to 108 TWh of renewables annually to meet its mandate, depending on growth in vehicle electrification, adoption of behind-the-meter solar and the success of energy efficiency programs.

That translates into 7,000 to 31,000 MW of new capacity, assuming a 40% average capacity factor, or 9,000 to 41,000 MW assuming a 30% capacity factor.

It also estimates building all of the transmission identified would cost more than $5 billion.

The TTIG said the capital costs included in the report are considered "conceptual" or "high-level" estimates that were derived from previous studies, which "should not be considered as reliable for specific resource addition purposes." Actual costs — including those for meeting the lower-end estimate of new renewables — will depend on a combination of factors, including the cost-effectiveness of developing a specific set of resources and the transmission paths

Continued on page 7

No End in Sight for PJM Capacity Market Changes

By Rory D. Sweeney

WILMINGTON, Del. — Still unable to reach consensus on the specifics of what to study, PJM members balked again last week at a request from a coalition of demand-side stakeholders to revisit the Capacity Performance construct.

By the end of the lengthy discussion at the Markets and Reliability Committee meeting Thursday, American Municipal Power's Ed Tatum, who has represented the coalition in committee discussions, admitted he was at his wit's end.

"I'm getting ready to curl up on the floor into a ball and roll around," he said.

But even without the coalition's initiative, stakeholders had plenty of capacity-related issues to discuss at last week's MRC meeting, debating underperformance rules, seasonal capacity and pseudo-ties. They also began considering another look at ways to limit capacity auction arbitrage.

Tatum's coalition continued to struggle with the scope of its proposed issue charge. The current issue charge suggests it is states'

Continued on page 23

NYPSC Vision for DER: From Net Metering to 'Value Stack'

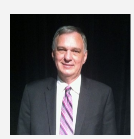
By William Opalka

Staff of the New York Public Service Commission released a report on Thursday recommending a transition from net energy metering (NEM) to a compensation scheme that provides more accurate, granular values for distributed energy resources (15-E-0751).

"With a more accurate, market-based approach to compensate consumers for the value of their distributed clean energy investments, we will continue to take positive steps towards making these clean resources a core part of our energy system," PSC Chair Audrey Zibelman said in a statement. "Under this cutting-edge

Continued on page 2

Also in this issue:



Crafters of Pa.'s Deregulation Law Look Back After 20 Years

The crafters of the 1996 law that brought retail choice to Pennsylvania gathered in Hershey on its 20th anniversary to reminisce and reflect on its effects. (p.21)

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

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

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

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

Production Editor
Michael Brooks 301-922-7687

MISO Correspondent
Amanda Durish Cook 810-288-1847

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

CAISO/West Correspondent
Robert Mullin 503-715-6901

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

PJM Correspondent
Rory D. Sweeney 717-679-1638

Subscriptions and Advertising

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

Account Executive
Marge Gold 240-750-9423

Marketing Assistant
Ben Gardner

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

Subscription Rates:

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

See details and Subscriber Agreement at rtoinsider.com.

NYPSC Vision for DER: From Net Metering to 'Value Stack'

Continued from page 1

framework, consumers, utilities and energy developers will be rewarded for investment decisions based on the full value that clean energy and other distributed energy resources provide to our electric system."

Phase One of the transition will seek to apply values "that were able to be considered and discerned with currently available data," the report says.

The mechanism will compensate customers using a tariff based on calculations of specific value sources. These value sources — including energy, capacity, reduced environmental impacts, demand reduction, locational system relief and distribution voltage support — would comprise a "value stack."

Phase One will apply to all projects and technologies eligible for NEM under current rules, including solar photovoltaic generation, wind and micro hydroelectric generation, where the operator has no ability to control the facility's output.

Also included would be dispatchable technologies such as fuel cells, farm waste generators and micro combined heat and power and energy storage paired with eligible generation facilities.

The report acknowledges that establishing these values will evolve and that utilities will need time to develop tools to calculate the impact of a resource's location, the services it provides and its time of use to fully compensate homeowners.

Staff is proposing interim measures for community distributed generation (CDG) projects — sometimes called shared renewables — that are in the advanced stage of development. The interim rules would allow a specific number of projects to be compensated under current net metering rules for 90 business days. After that period, future CDG projects would be valued under the new methodology.

The report also envisions "virtual generation portfolios" codeveloped by utilities and DER providers.

Existing rooftop solar facilities would be paid at net metering rates for 20 years from the date of their installation. Since 2012, solar facilities in the state have grown from a little more than 78 MW to the current 669 MW, the PSC says. Owners of the systems would have the option to drop net metering and sign up for updated compensation plans.

Public comment will be accepted on the report, part of the state's Reforming the Energy Vision initiative, until Dec. 5. Initial PSC action is expected in January.

Phase Two of the process, which would further refine the development of DER metrics, is slated to begin with a collaborative later this month. A final order is anticipated by the end of 2018.

Net Metering's Shortfalls

The report said that while it "has been an important and effective tool in fostering the growth of" DER, "when combined with traditional volumetric rate structures, NEM provides an imprecise and incomplete signal of the full value and costs of DERs."

"NEM therefore provides insufficient information on which to base informed investment and usage decisions that could benefit both the system and customers

Continued on page 18

Category	Compensation Method
Avoided System Energy Costs (including avoided zone-to-zone transmission value and avoided losses)	\$/kWh (varies by hour and location)
Avoided Generation Capacity Costs (including avoided reserves per kW of load and avoided losses)	\$/kW (coincident with system peak)
Delivery Costs	\$/kW (coincident with local peak)
Avoided Societal Damage/Mitigation Costs*	typically \$/kWh*

Valuing the benefits of clean distributed generation | *NYPSC*

CAISO News

Foes Narrow Differences at FERC Summit on EIM Bidding

By Robert Mullin

A technical conference that convened at FERC headquarters last week to explore external resource participation in the Energy Imbalance Market (EIM) began on a contentious note but concluded with parties on both sides of the issue admitting to a better understanding of the others' perspectives (ER16-1518).

The commission ordered the staff-led conference in June when it rejected CAISO's proposal to prohibit EIM members from implementing economic bidding at the market's interties until the ISO could develop "appropriate rules" to manage the transactions. (See *FERC Order Prods CAISO to Allow EIM Intertie Bidding*.)

The ISO's Tariff stipulates that each balancing authority area (BAA) that joins the EIM can determine for itself whether to allow resources located outside the market to submit economic bids at the BAA's transmission seams. Two factors prompted the ISO to seek to undo the provision.

First, EIM participants PacifiCorp and NV Energy had expressed concerns that implementing the practice would add complexity to their initial participation in the market. Second, the ISO said its own experience with low liquidity in 15-minute bidding at its own seams suggested that the benefits of allowing such bidding was "questionable."

Power Marketers Weigh In

The Western Power Trading Forum (WPTF), a group of power marketers, filed the only protest against the proposal, saying the amendment was an "attempt to codify" an "effective roadblock to market evolution" that discriminated against third-party participation in the EIM.

That argument found support with FERC, which called for further discussion on the issue.

CAISO laid out its perspective in its opening remarks at the conference.

"We must be careful not to impose requirements that degrade the fundamental design elements of the Energy Imbalance Market that could ultimately unravel the benefits the Western market is experiencing," said Mark Rothleder, the ISO's vice president of market quality and renewable integration.

The position staked by WPTF and other stakeholders created that risk, Rothleder said. He added that there is a "misperception that there is an easy plug-and-play format" for intertie bidding that EIM entities can adopt.

"That is because the EIM addresses a set of necessary but complicated and interrelated issues, such as resource sufficiency, transmission utilization and compensation, resource flexibility, market power mitigation, greenhouse gas accounting, feasibility of flows across the network, feasibility of the resource dispatches and performance monitoring," Rothleder said.

New market design elements cannot be imposed without considering all of those factors, Rothleder contended.

CAISO Pans 'Generic' Bidding

"Generic" intertie bidding — bids by unspecified resources on a system neighboring the EIM — is "not consistent with the principles of the EIM," Rothleder said.

In August, the ISO began work on a plan that would require external participating resources to have characteristics comparable to those already participating in the EIM. These "specified resources" would have 15-minute scheduling and five-minute dispatch capability. They would also have to meet data exchange, settlements and metering requirements in order to verify delivery.

> **"Issues of open access seem of the category of right versus wrong — and sometimes right is not the most popular."**
>
> **Ellen Wolfe, WPTF**

(See *CAISO Charts Course for External Resource Participation*.)

Rothleder added that there is no evidence that the absence of generic bidding is imposing hardship on the West's bilateral markets.

"Moreover, we cannot waste ISO and stakeholder time and resources [on efforts] that are not wanted by other market participants as a whole," Rothleder said.

Ellen Wolfe, a consultant representing the WPTF, challenged Rothleder, contending that the Western marketplace has in fact "lost some functionality with the advent of the EIM." Within the EIM area, she explained, market members and a "small number" of third-party participants can bid into the EIM's 15- and five-minute markets on an economic basis.

However, participants outside the market's boundary cannot bid into an EIM member's balancing area during those intervals; instead they are forced to bid an hour in advance — a byproduct of the need for an EIM member to come into each hour fully balanced.

The process exposes outside resources to unknown congestion charges and forces them to become price-takers of the market's intra-hour adjustments, Wolfe said.

Before the EIM, a party holding system energy — energy from an unspecified resource — could schedule through a utility area and make changes up to 20 minutes before delivery with no price impact. Currently, schedule changes with an EIM member now incur an unpredictable fee for nonperformance within the hour — even for power being wheeled through the member's balancing area.

Under WPTF's counterproposal, offers from resources outside the EIM would be bid into the market on a 15-minute basis. CAISO could fold those bids into its EIM runs and dispatch with other market resources "with little or no burden on the EIM entity," Wolfe said.

External offers would have the same

Continued on page 4

CAISO NEWS

Foes Narrow Differences at FERC Summit on EIM Bidding

Continued from page 3

performance obligations as those originating internally and would be subject to the same imbalance energy risks, Wolfe said. The resulting solution would provide the increased efficiency of a deeper bid stack, which could relieve concerns about market power in certain areas of the EIM, she said.

'Not Bullish' on Stakeholder Process

Wolfe was skeptical of CAISO's contention that the issue could best be resolved by stakeholders, saying that she was "not particularly bullish on that process" based on past experience. Issues related to open access are not "appropriately left for a process that depends on a popular vote," she said.

"Rather, issues of open access seem of the category of right versus wrong — and sometimes right is not the most popular," Wolfe said.

Speaking on behalf of the EIM's present utility members, Sara Edmonds, general counsel for PacifiCorp Transmission, pointed out that each member allows for external participation through pseudo-ties or dynamic schedules.

Edmonds also spoke about the three "critical elements" needed for "effective EIM diversity": generating resources, load and transmission.

"Alternatives — or derivatives — to full participation which deviate from these fundamentals could threaten the long-term success of the EIM, as well as its continued growth," Edmonds said, citing concerns about the shifting of costs and risks to EIM members.

No Desire to be Market Operator

One risk is that EIM BAAs will become responsible for balancing multiple remote sources of external generation at multiple intertie points.

"We signed up to be a market participant, but not a market operator," said Justin Thompson, director of resource operations and trading at Arizona Public Service. "If we go with intertie bidding, we're going to turn into a quasi-market operator."

Thompson also voiced concern about the potential for "free riders" on the EIM system, noting that some of APS's neighboring utilities are considering market membership.

"Instead of joining the full market, they can just intertie bid at our boundary and take up all our transmission that we're using for EIM participation," Thompson said.

Therese Hampton, executive director for the Public Generating Pool (PGP), which represents 10 municipal utilities in Oregon and Washington, voiced the perspective of small organizations that don't have the financial means to join the EIM but could still benefit from — and provide benefits to — the market.

Hampton said that EIM members with diverse resource portfolios stand to benefit the most from joining the market. However, PGP's members own mostly hydroelectric resources, control little transmission and deal with limited load and congestion.

Given the limited financial upside of joining, the EIM's upfront costs are a difficult sell for ratepayers, Hampton said. "We believe there should be another option."

Not 'Free Riders'

While PGP is open to market rules that require specific information from external resources, the group also wants the ISO to consider allowing resource aggregation, just as it does for internal resources.

"We've never intended or want to be free riders," Hampton said, acknowledging that PGP recognizes that participation could come with "appropriate" administrative costs.

PGP's resources have the surplus capacity and flexibility to participate in the market on the five-minute basis, Hampton said. She also added that the EIM's rules for external participation should be developed by CAISO and not be relegated to individual BAAs, as the Tariff currently stipulates.

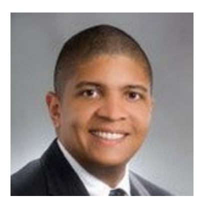
Rothleder pointed out that CAISO had no experience with 15-minute bidding at its own interties when it was designing the EIM. At the time, it thought the determination for allowing intertie bidding was best left to each EIM member as the entity most familiar with its own transmission capabilities.

"It is not the same thing as the ISO's intertie bids at the border," Rothleder said. He pointed out that EIM members have to contend with other protocols related to transmission allocation that overlay their own participation in the market — something not applicable to the ISO as a central market operator.

Shahzad Lateef, director of transmission and distribution system operations at NV Energy, described the complexity of participating in the EIM, which entails responding to intertie bids administered by the ISO while maintaining reliability within its own BAA.

"Every resource that CAISO dispatches higher, we have to look at all our congestion elements," Lateef said, explaining the utility's need to know exactly what sink a dispatched resource is intended to serve, even in neighboring EIM BAAs.

"The complexity continues to increase when you think there's the potential of 35 tie points with so many potential bidders that will all be moved up or down based on their bid value by someone other than NV Energy," Lateef said.



Robb Davis, energy policy advisor for Chelan County Public Utility District, noted that his utility sells a large slice of its hydroelectric output to EIM member Puget Sound Energy, which pseudo-ties the resource into its own BAA. While the utility is reluctant to take on the cost of EIM membership, as a holder of surplus generation, it does sell additional slices of its output to other marketers and utilities that want access to the market.

Davis noted that Chelan's resources are situated in an area already modeled by the ISO — and the telemetry is already in place to monitor performance.

"It shouldn't be an impediment to their

Continued on page 5

CAISO NEWS

Foes Narrow Differences at FERC Summit on EIM Bidding

Continued from page 4

participation that we as a balancing authority area don't want to incur those costs for our customers in our county," Davis said.

BPA's Intent

Suzanne Cooper, vice president of bulk marketing at Bonneville Power Administration, said that while her agency isn't preparing to join the market now, it might consider doing so in the future.

"Whatever principles we apply for external resources to participate in the market should be the same whether we're in the market or we're not."

Mike MacDougall, director of trade policy at Powerex, conceded that generic external bidding at the interties might not be the best solution for facilitating external participation. But he said that BPA, PGP and Powerex would be willing to work with the EIM to develop a participation model that addresses issues such as free riders and transmission usage.

"That's premised on the fact that there are benefits that arise from that broader participation and liquidity and production costs savings," MacDougall said.

"I do appreciate Ms. Hampton trying to tease out and separate the issues of smaller BAs who want to come and be part of the [EIM's] optimization process," said **Lauren Rosenblatt**, an attorney with NV Energy. "And if there are barriers to entry for smaller BAs to join the EIM, then — listening to my colleagues who are all EIM entities over the last nine months — we all embrace addressing that."

Rosenblatt said existing EIM members are excited about Sacramento Municipal Utility District's recent announcement that it intends to join the market because the utility brings the "trifecta" of load, resources and transmission. (See related story, *SMUD to Join EIM in Spring 2019 at the Earliest*, p.6.)

To Be Continued

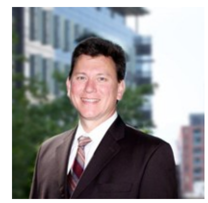
Conference participants wrapped up the day on a conciliatory note.

CAISO Assistant General Counsel Anna McKenna encouraged parties outside the EIM to participate in the processes developed to address West-wide issues, particularly the ISO's Regional Issues Forum and EIM governing body meetings.

"We have a lot of ways for these issues to be vetted or get more attention," McKenna said. "What would be really helpful is to continue this dialog and focus in a little better on resolving specific issues."

Wolfe said hearing "the other parties' concerns was very beneficial." She also lauded "the amount of brainstorming" that came out of the FERC session, saying it suggested that the ISO might already have the functionality to solve some of the problems related to external participation.

"I wonder if there might be a way to sort of continue that without taking on these big "I" initiatives," Wolfe said, adding that the ISO's forums could serve as venues for more discussion.



Robert Cromwell, director of power contracts and resource acquisition at Seattle City Light, offered a "concrete suggestion" to CAISO: "Perhaps having the ISO articulate specifically the technical requirements for an external resource participant — consistent with current market design — might help inform those prospective participants and be a foundation for further dialogue and discussion."

CAISO's Rothleder called the conference "enormously helpful" in furthering the discussion, adding that current EIM participants might have to consent to removing some of the current barriers to entry in order to foster expansion of the market.

"I hope we can all come to the table with an open mind," Rothleder said.

PacifiCorp Increases Share of EIM Benefit in Q3

By Robert Mullin

PacifiCorp reaped more than half the $26.16 million in gross benefits yielded by the Western Energy Imbalance Market (EIM) during the third quarter, market operator CAISO said in a report released Wednesday.

The Portland-based utility earned $15.1 million in benefits — versus $5.6 million for NV Energy and $5.4 million for the ISO. Last quarter, PacifiCorp took in a 45% share.

The EIM's total benefit increased by $2.56 million over the second quarter.

The benefits represent either cost savings — for example, the reduced need for reserves and greenhouse gas credits — or increased profits from merchant operations. The market's ability to reduce curtailments also enables participants to collect renewable energy credits that would not otherwise be issued.

The benefits calculation nets out inter-balancing authority area (BAA) transfers that were scheduled ahead of the EIM's 15- and five-minute market runs to avoid attributing contracted flows to the market.

Transfers from the PacifiCorp East (PACE) BAA into NV Energy's territory increased sharply during the period, as did transfers from NV Energy into CAISO — reversing a pattern seen during the previous quarter, when California was able to export a significant volume of surplus solar generation because of low springtime loads.

The ISO's exports into NV Energy fell by more than half, following a 56% jump the previous quarter. (See *EIM Report Shows Continued Growth in CAISO Exports*.)

The drop-off in exports was largely a function of the change in seasons, Khaled Abdul-Rahman, the ISO's director of power systems and smart grid development, told the Board of Governors during an Oct. 27 meeting. "This is because of increased [summer] load," which absorbed more solar

Continued on page 6

CAISO NEWS

SMUD to Join EIM in Spring 2019 at the Earliest

By Robert Mullin

The Sacramento Municipal Utilities District (SMUD) will join the Western Energy Imbalance Market (EIM) in spring 2019 at the earliest, according to the head of the joint powers agency of which the utility is the largest member.

"As you might guess, this is a very intense technical project," Jim Shetler, general manager of the Balancing Authority of Northern California (BANC), told *RTO Insider*.

The four utilities that have joined the EIM to date have required 18 to 24 months to begin operating in the EIM after signing an implementation agreement with CAISO, the market's operator.

SMUD will likely sign such an agreement early next year, Shetler said. "We're just starting to meet with the ISO to lay out project plans."

The utility announced its intention to join the EIM on Oct. 21, citing the benefits of increased renewable integration, potentially reduced reliance on gas-fired generation and lower operational costs. (See *Sacramento Utility to Join EIM; Other BANC Members May Follow*.)

SMUD would be a first municipal utility to sign up for the market — a status that could potentially complicate its efforts to join. Municipal utilities are not subject to FERC jurisdiction — but the EIM is. (See *Co-ops, MISO, SPP Urge FERC Restraint with Nonpublic Utilities*.)

"With FERC oversight, we're trying to understand what that would mean," Shetler said. "SMUD has an open access transmission tariff that was approved by its board, but not by FERC."

SMUD already operates under an agreement that enables the utility to bid power into CAISO through a single hub in which one proxy price is selected to represent all connection points between the two areas.

A joint study conducted by BANC and the Western Area Power Administration estimated that SMUD would gain $2.8 million in yearly net benefits from transacting in the market — a figure that nets out an estimated $6.7 million in implementation fees and $2.6 million in annual operations costs.

Shetler said that SMUD's annual benefit could increase to about $5 million after five years, once the utility has paid down startup costs.

"It's a big number, but a small number compared with their energy resource portfolio," Shetler said. The real value will come in integrating the increased number of variable resources needed to meet California's 50% by 2030 renewable energy mandate, he noted.

SMUD would be breaking ground for possible future EIM participation by BANC's other municipal utility members, including Modesto Irrigation District and the cities of Redding and Roseville.

Two other members — the city of Shasta Lake and Trinity Public Utilities District — own no generating resources and would therefore derive no benefit from joining the market, Shetler said. Trinity, a "full requirements" customer of WAPA, receives all of its energy from the federal agency.

Could other BANC members piggy-back on SMUD's efforts and reduce their costs to join the EIM?

"We're hoping that's the case," Shetler said. "We think there is some scale there.

"Not that it would be on the backs of SMUD or its ratepayers," he added.

Established in 2011, BANC is the third largest balancing area in California and the 16th largest of the 38 balancing areas in the Western Electricity Coordinating Council. The agency is responsible for balancing load among its members, as well as coordinating system operations with neighboring balancing areas.

BANC contracts with SMUD to perform day-to-day balancing functions.

The BANC-WAPA study spelling out EIM benefits is slated to be released to the public in late November.

PacifiCorp Increases Share of EIM Benefit in Q3

Continued from page 5

production, he said.

Even in their reduced state, those exports enabled the ISO to avoid curtailing 33,094 MWh of renewable generation.

CAISO also touted the EIM's impact on the procurement of flexible ramping capacity — resources equipped to respond to the variability of intermittent generators.

Because variability can decrease in one BAA at the same time that it's increasing in another, the EIM enables its participants to share flexible resources — allowing each BAA to procure fewer resources than would have been necessary on a standalone basis. These "flexible ramping procurement savings" were about 35% of total savings during the third quarter, the ISO reports showed.

The next quarterly report will include figures for Arizona Public Service and Puget Sound Energy, which began trading in the EIM at the beginning of October.

Abdul-Rahman gave the two utilities high marks for their market performance so far, noting that both have been coming into hourly intervals with balanced schedules more than 96% of the time.

"They are doing very well in managing their system," he said.

He also pointed out that interconnected balancing areas within the EIM are seeing steady bidirectional transfers, indicating a true sharing of resources.

"We're happy to see this kind of transfer — and that sometimes they're importing or exporting," Abdul-Rahman said. "That means the EIM is doing its job."

Region	July	August	September	Total
ISO	2.24	1.38	1.82	5.44
NV Energy	1.88	2.16	1.55	5.60
PacifiCorp	6.09	4.92	4.12	15.12
Total	10.21	8.46	7.49	26.16

EIM Q3 2016 benefits | *CAISO*

CAISO News

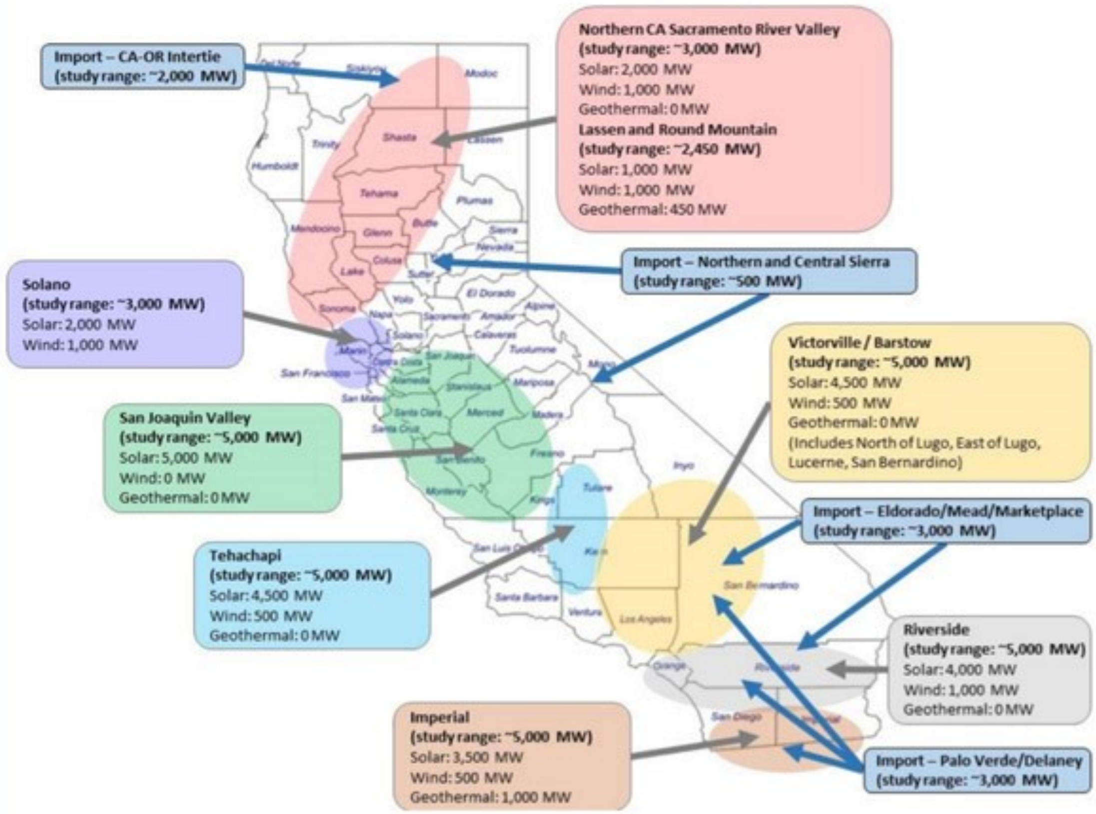
Price Tag on Tx Needed to Meet California 50% RPS: $5B?

Continued from page 1

necessary to reach them.

Publication of the study comes two months after a public workshop in which transmission planners reported a portion of their findings to state officials. (See *California Policy Goals to Require Significant Transmission Upgrades*.)

While California has a "substantial amount" of non-firm capacity to interconnect new generators as energy-only resources subject to curtailment, the state falls short in the availability of full-capacity interconnections equipped to ensure that output is "fully deliverable" — or capable of reaching its load sink without hitting potential constraints.



The Renewable Energy Transmission Initiative report examined the potential for developing renewables in eight California regions — as well as the transmission cost for reaching the resources. | *California Energy Commission*

California rules allow the state's utilities to count only fully deliverable generation toward their resource adequacy requirements, excluding energy-only resources. For that reason, the TTIG, headed by CAISO Director of Infrastructure Development Neil Millar, assumed that all new renewable resources would require full-capacity interconnections.

CAISO can accommodate an additional 22,000 MW of energy-only resources, the report notes. The ISO is so far the only balancing authority area in the state to have studied the issue, so other BAAs have the potential to contribute additional energy-only capacity.

To perform its analysis, the TTIG broke the state into eight transmission assessment focus areas (TAFAs) where the large quantities of renewables could be developed to meet the state's 2030 goals.

"The TAFAs identify a 'hypothetical' development potential for wind, solar and, where applicable, geothermal resources," the report says.

Those hypotheticals show a combined 15,000 MW of potential renewable development — mostly solar — in Southern California's Imperial Valley, Riverside and Victorville/Barstow areas. To tap some of that potential, load-serving entities could have to foot up to $1 billion to relieve a constraint east of the Miguel substation close to the border with Mexico. A $34 million upgrade to the relatively short 500-kV Lugo-Victorville line could provide 2,000 MW in incremental capability, the report shows.

In the central part of the state, the San Joaquin Valley and Tehachapi TAFAs together have the potential for another 10,000 MW of mostly solar resources. While San Joaquin would require about $400 million in transmission upgrades, Tehachapi would require a negligible amount of work.

The least promising area: all points north of San Francisco and Sacramento, where it would cost $2 billion to $4 billion to tap an estimated 5,450 MW of wind, solar and geothermal resources — the largest share of the $5 billion estimate.

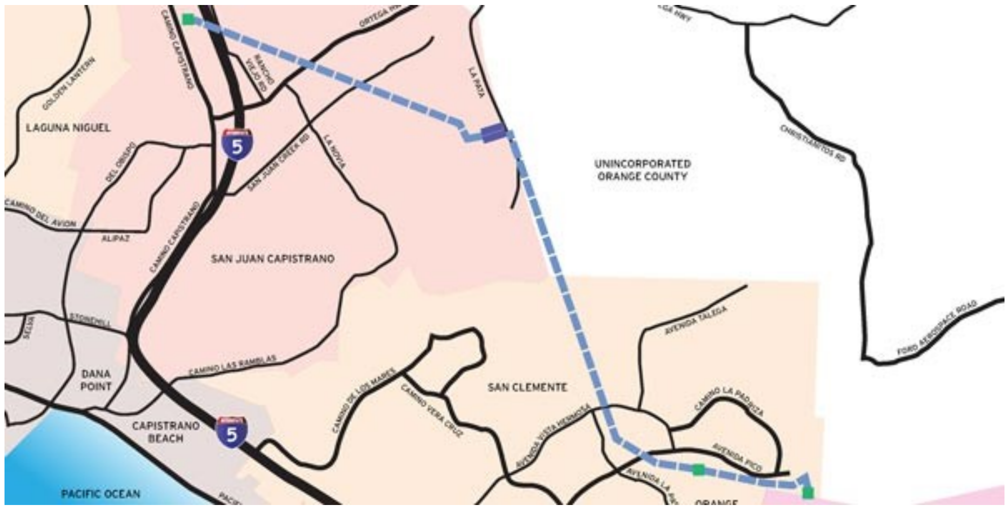
"The bulk transmission system in the region is heavily utilized and would require substantial investment to allow for the delivery of new full capacity resources," the report says.

The study also evaluated the potential for sourcing additional renewable energy via California's major interties, including the California-Oregon Intertie in the north (2,000 MW), the Palo Verde-Delaney line to Arizona (3,000 MW) and the Eldorado/Mead/Marketplace (3,000 MW) links with Nevada. All three were found to be subject to the same constraints as the TAFAs with which they interconnect, compounded by the fact that the imported energy would compete with TAFA resources for transmission access.

CAISO NEWS

FERC Denies Rehearing on SDG&E Abandonment Incentive

By Michael Brooks



South Orange County Reliability Enhancement Project map | *SDG&E*

FERC on Wednesday denied San Diego Gas & Electric's request for rehearing of an order that limited the amount the utility can be reimbursed if its South Orange County Reliability Enhancement (SOCRE) transmission upgrade project is canceled (EL15-103).

SDG&E is seeking approval from the California Public Utilities Commission to construct the $400-million project, which involves rebuilding two substations in the cities of San Juan Capistrano and San Clemente and replacing the current single-circuit 138-kV transmission line with a double-circuit 230-kV line.

The project, which was included in CAISO's 2010-2011 Transmission Plan to address reliability in southern Orange County, has been mired in the PUC's review process. The utility filed for approval in May 2012; the PUC issued it final environmental impact report in April.

In September 2015, SD&E asked FERC for an abandonment incentive under Order 679, which allows recovery of 100% of all "prudently incurred" costs if the project is canceled for reasons beyond the company's control.

On March 2, FERC granted the utility's request, but only for those costs incurred after the date of the order. For the more than $31 million SDG&E spent prior to then, FERC ruled the utility could only recover 50%.

SDG&E protested, saying the order went against commission precedent. FERC summarily dismissed this claim.

"It is commission policy that a public utility may only recover up to 50% of prudently incurred abandonment costs for costs that are incurred before the date of the order granting the incentives," FERC said. "While SDG&E refers to this precedent as 'outlier cases,' they are in fact the only cases that speak in some way to the issue of retroactive application of an abandonment incentive under Order No. 679."

FERC's order came a day before the California PUC delayed a final decision on the project until its Dec. 15 meeting.

CAISO Board Approves Broader LSE Definition

By Robert Mullin

CAISO's Board of Governors voted Thursday to expand the definition of a "load-serving entity" to include the San Francisco Bay Area Rapid Transit District (BART) and other organizations that buy wholesale power to serve their own needs.

"This was really sparked by BART rolling off of a [Pacific Gas and Electric] contract and wanting to serve their own load," Greg Cook, the ISO's director of market and infrastructure policy, told board members. (See *CAISO Issues Revised Proposal to Expand LSE Definition*.)

CAISO's Tariff currently defines LSEs as entities that serve load or sell electricity to end users, which includes utilities, federal power marketing agencies and community choice aggregators. A special Tariff provision was made for the State Water Project (SWP), a California agency that trades in the wholesale market to cover its own energy requirements.

Like the SWP, BART already serves its own load, doing so through transmission contract rights that precede the existence of the ISO. That contract is scheduled to expire at the end of this year, exposing the agency to congestion charges without the ability to acquire an allocation of congestion revenue rights (CRR) available to recognized LSEs.

The definition change would permit entities such as BART to receive a free CRR allocation in the ISO's annual process, but it will also subject them to resource adequacy requirements.

That second point had prompted worry among stakeholders who thought the original proposal — which would have broadened the definition to include any entity granted the authority to serve its own load — would subject transmission contract holders to capacity requirements.

CAISO responded to that concern by tightening the language to specify that an organization would have to elect to serve its load to be subject to capacity requirements.

"We didn't want to unintentionally include existing transmission contract rights holders," Cook said.

The Tariff change still requires FERC approval.

ERCOT NEWS

ERCOT Maps out Plan for Changing Reserve Margin Methodology

By Tom Kleckner

AUSTIN, Texas — Texas regulators on Friday signed off on ERCOT's plan to review its reliability standards and replace its loss-of-load expectation (LOLE) methodology for determining its reserve margin with one based on economics.

The Public Utility Commission agreed that a letter filed with the commission by ERCOT Director of System Planning Warren Lasher on Oct. 24 outlined a sound process. "Go forth and do good," Chairman Donna Nelson said.

Commissioner Ken Anderson pointed out the project's (Docket 43202) intention is to replace ERCOT's LOLE methodology with the economic optimal reserve margin (EORM).

The LOLE is "not really baked into any of our rules, but it is baked into the protocols at ERCOT," Anderson said.

ERCOT staff will go through its protocols to find language that needs to be modified and make changes "at the appropriate time," Lasher replied.

In 2013, The Brattle Group and Astrapé Consulting conducted a study of the market's EORM, which it defined as minimizing total system costs by weighing the cost of more generation to achieve higher reserve margins against decreasing scarcity-event-related costs.

Higher reserve margins help to avoid load shedding, reserve shortages, demand response calls and other emergency event costs, the study said.

The firms had to customize the study's methodology, Lasher wrote, "to reflect the region's unique energy-only deregulated wholesale market design and region-specific market behavior."

The study simulated ERCOT's recently implemented operating reserve demand curve. Lasher said that methodology and other study assumptions will need to be reviewed by ERCOT and stakeholders "if the results of future EORM studies are to be used in place of the existing target reserve margin."

Lasher's proposal involves conducting workshops with market participants in the first half of 2017 and completing its next EORM study in 2018 based on the documented methodology. He recommended future EORM analyses be conducted every other year coincident with NERC's required LOLE studies.

Following the 2018 EORM study, Lasher said ERCOT would amend its market rules as appropriate to accommodate the move to a target reserve margin based on EORM criteria, and away from the one-event-in-10-years LOLE.

"Currently, NERC has two numbers that go to them," Lasher told the PUC. "First, what the region says is an appropriate reserve-margin expectation. That's whatever the region wants to define it as. Some regions use the economic optimal number.

"NERC also has a standing data request every year for the region to say, given our expectations for the reserve margin, what will actually be the expected unserved energy with that margin."

Lasher said ERCOT conducted loss-of-load probabilistic studies in 2014 and 2016 to comply with data requests from NERC and the Texas Reliability Entity. The ISO worked directly with Astrapé to complete the studies, using the same models and assumptions comparable to those employed for the 2013 study.

The commissioners debated whether to have ERCOT continue providing its regular capacity, demand and reserves (CDR) report until the new reliability standards are in place, without coming to a decision.

"The CDR is at the heart of the problem, because its load assumptions are beyond four years," Anderson said.

Anderson suggested ERCOT take the 2013 study results and incorporate them in the CDR, using the economical, optimal and expected equilibrium as information data points. Lasher noted ERCOT's May CDR didn't provide data for a target reserve margin, but he said staff could include the Brattle study's results.

TAC Briefs

Distributed Generation Remains Growing Concern

AUSTIN, Texas — ERCOT staff told the Technical Advisory Committee last week it is preparing a proposal to map registered distributed generation units and a white paper addressing the reliability of distributed energy resources.

The work builds partly on that of the Distributed Resource Energy and Ancillaries Market (DREAM) Task Force, which produced a draft report earlier this year before going inactive. (See "DREAM Task Force Submits Final Report," *ERCOT Technical Advisory Committee Briefs*.)

TDSP Type	'Self-Dispatched'		Renewable	
	Units	MW	Units	MW
Competitive	46	360	7	37
NOIE	8	64	16	81
Totals	54	424	23	118
Grand Totals: 77 Units; 541 MW				

Notes:
- Aggregated Data for Registered Distributed Generation > 1MW and injects to grid.
- Self-dispatched includes Natural Gas, Distillate Fuel Oil, Landfill Gas.
- This data is available via an MIS Extract. Numbers do not match due to rounding.

Registered distributed generation on 10/26/16 | *ERCOT*

Continued on page 10

ERCOT NEWS

TAC Briefs

Continued from page 9

“We’re trying to look into what we need for the future … and focus our attention on improving our reporting requirements,” Kenan Ögelman, ERCOT’s vice president of commercial operations, told the TAC on Thursday.

As of late October, 541 MW of DG from competitive and “non-opt-in” entities — those not participating in the market, such as Austin Energy and San Antonio’s CPS Energy — had registered with the Public Utility Commission through their local utilities. The commission has estimated there are more than 7,600 DG locations in competitive areas, with the load expected to grow at a 10% annual rate.

Unregistered DG accounts for another 112 MW in ERCOT’s various load zones. Ögelman said there is no requirement for the ISO to gather data on unregistered DG, but that it occurs “more by happenstance.”

Under current rules, distributed resources injecting to the grid are paid the load zone price, allowing them to deliver energy in real time but giving ERCOT no notification of their intent to deploy.

In addition, distributed resources are compensated by load-zone pricing regardless of their location within the zone or their impact on congested elements. ERCOT says development of a resource node for distributed resources would improve reliability and the ability of DER to participate in its market.

ERCOT defines DG as any generating facility of 10 MW or less located at a customer’s point of delivery and connected at a voltage less than or equal to 60 kV.

Ögelman said ERCOT currently compiles DG data on from a variety of sources:

- Load profiles and annual reports to the PUC for resources less than or equal to 50 kW;
- Load profiles, PUC reports and unregistered DG reports for resources greater than 50 kW, but less than or equal to 1 MW;
- PUC reports and unregistered DG reports for resources greater than 1 MW that are not exporting to the grid; and

© RTO Insider

- ERCOT resource asset registration forms for non-modeled generation, but only from resources greater than 1 MW that export to the grid.

He explained that ERCOT no longer “ratchets down” its reporting of DG resources. Nodal protocol revision request (NPRR) 719, which was approved by the Board of Directors last December, removed a provision that reset DG registration thresholds when the total unregistered capacity of DG greater than 50 kW in any load zone reaches 10 MW. “There was an expectation of, ‘Hey, what’s going on? We have all this DG on the system, but there’s no ratcheting going on?’” Ögelman said.

He said staff is working with stakeholders and other interested parties to find a way to draft NPRR language “that addresses everyone’s concerns.” The white paper, Ögelman said, will “show the concern for reliability outcomes.”

Stakeholders had suggested staff use the annual load data request (ALDR) forms to track distributed resources, but Ögelman said, “The ALDR reports don’t have a very well-defined reporting requirement or change process around them.

“It’s difficult to aggregate and see a very good picture of the submitted load data to ERCOT.”

IT Staff Working to Prevent Further SCED Outages

Steve Daniels, ERCOT’s vice president of application development and IT operations, assured stakeholders that staff is working to prevent a repeat of recent outages of the security constrained economic dispatch (SCED) system.

In July, human error led to a 100-minute outage that affected 20 five-minute dispatch intervals. In October, a software failure with the market-management system’s interface resulted in a 75-minute outage. Two smaller SCED failures related to hardware issues also occurred in August and September. Load frequency control signals were also affected in the first three outages.

Daniels noted while SCED has failed in each of the last four months, the system operated smoothly in his first 16 months on the job. He said staff completed a “very thorough” root-cause analysis after each event, using both internal and external resources.

“I can assure you the attention paid to these [outages] and the amount of effort going into remediation, lessons learned and finding ways to ensure we don’t have this going forward is a very concentrated and focused effort,” Daniels said.

He told stakeholders staff is implementing new monitoring procedures, adding new software and working with its vendors “to make sure we don’t see these same issues pop up again.”

Daniels said additional measures have been added around the SCED system “to give us better visibility when those issues arise and what we can do about them.”

That seemed to satisfy stakeholders, who asked Daniels whether there is a way to avoid future single point-of-failures, where one system affects another. He said staff is continuing to “look at ways where we can make … data available to operate the system effectively and reliably when we have SCED issues.”

Continued on page 11

ERCOT NEWS

TAC Briefs

Continued from page 10

TAC Approves Ancillary Service Change, Tx Element List

The TAC unanimously approved staff's proposal to make two minor changes to its 2017 ancillary service methodology. The first removes exhaustion-rate feedback from the regulation-procurement analysis, and the second adds solar generation when estimating five-minute net-load variability.

"We have 400, 450 MW of solar, so we think it's useful to start capturing the effects," ERCOT's Nitika Mago said.

No changes were proposed to the methodologies for determining responsive-reserve service and non-spin reserve service.

The committee also endorsed the Reliability and Operations Subcommittee's recommendation to approve ERCOT's original list of high-impact transmission elements. The list will be expanded once a working group can be chartered.

NRG Texas abstained from the vote, saying it had been "late to the party" and was unable to get its comments in. The list "seems to be more backward-looking, based on an analysis of historical congestion," NRG's Bill Barnes said. "If [an element] didn't cause congestion in the past, it's difficult to get on the list."

11 Revisions Sent to ERCOT Board

The TAC pulled NPRR773 from the list of revision requests up for a vote. Barnes, chair of the Market Credit Working Group, said the revision request includes language that expands the types of financial institutions that can offer letters of credit, but that outside counsel has proposed additional changes that are "more substantial" than those approved by his group.

The committee did approve five NPRRs, two nodal operating guide revisions (NOGRRs) and revisions to the load profiling guide (LPGRR), retail market guide (RMGRR), resource registration glossary (RRGRR) and the Verifiable Cost Manual (VCMRR).

- NPRR783: Revises a requirement for an independent audit to confirm the consistency of ERCOT operations models. The change is to comply with NERC reliability standard MOD-033-1 requiring a documented data-validation process for power flow and dynamic models.
- NPRR790: Adds phase angle equipment limitations to real-time monitoring, real-time assessments and operational planning analyses, as required by NERC standards. ERCOT will collect this information through the network operations modeling process.
- NPRR791: Clarifies the initial estimated liability (IEL) description to specify that it is based on estimated sales between qualified scheduling entities (QSEs); restores the IEL for traders (inadvertently omitted from NPRR741); and corrects errors to the minimum-current exposure formula mistakenly overwritten by NPRR743.
- NPRR797: Creates a new report and display for the actual system load by forecast zone, similar to the capability for weather zones.
- NPRR801: Revises the physical responsive capability (PRC) calculation to include all load resources and align operating reserve demand curve (ORDC) reserves with the PRC change. It also aligns the ancillary service imbalance settlement with the change to the ORDC reserves.
- LPGRR057: Updates the load profiling guide by eliminating language, processes and methodologies no longer necessary within ERCOT's market.
- NOGRR154: Allows a QSE to designate an agent to connect to ERCOT's wide area network (WAN) and requires the ISO and market participants to use the WAN to exchange resource-specific XML data.
- NOGRR159: Modifies the use of the term Texas Reliability Entity to distinguish between references to the NERC Regional Entity and the Texas PUC Reliability Monitor. It also clarifies that the Independent Market Monitor is an included party in several provisions related to the ERCOT stakeholder process.
- RMGRR139: Modifies market processes to align with NPRR778's changes to the protocols' evaluation window for date changes and cancellations.
- RRGRR010: Amends the seasonal net max sustainable rating definitions by including ambient conditions (including temperature and humidity) representative of conditions that exist during peak load periods in which the generation resource operates. The change is intended to correct an overestimation of summer capacity ratings for gas-fired generation. ERCOT discovered the same temperature value had been used for summer and winter seasonal ratings for a significant number of gas-fired units, with resources reporting temperatures of 36 to 110 degrees F for their summer ratings.
- VCMRR013: Clarifies the process for appealing ERCOT's denial of submitted verifiable costs. The changes address timelines and ERCOT representation in the appeal process and align with NPRR769, approved by the board Oct. 11.

— Tom Kleckner

ISO-NE NEWS

New England States Move Toward Renewables Contracts

By William Opalka

"We are pleased with the key approvals the project continues to receive and look forward to participating in the April solicitation for large-scale hydroelectricity."

Bill Quinlan, Eversource New Hampshire Operations

Developers of six renewable projects totaling about 460 MW will start contract negotiations with New England states in the next phase of a multistate effort to procure clean energy.

Project solicitors last week completed the evaluation phase of the New England Clean Energy request for proposals. (See *New England States Combine on Clean Energy Procurement*.)

Four of the projects will negotiate with three states: Connecticut, Rhode Island and Massachusetts; two projects will proceed with only Rhode Island and Massachusetts. The solicitation generated 24 responses from 30 developers, some in teams.

"Not all projects selected to advance to contract negotiation at this stage will necessarily obtain approved contracts, which may affect the total contracted megawatts resulting from this" request for proposals, the states said in announcing the selections.

The states said they expect to negotiate better power prices in combination than they would have if they acted alone.

Most of the generation would come from solar projects. The selected bidders are:

- Ranger Solar, with five solar projects totaling 220 MW in Connecticut, Maine and New Hampshire;
- Deepwater Wind's 26-MW solar facility in Connecticut;
- Ameresco's 20-MW solar project, also in Connecticut;
- Antrim Wind's 26-MW wind project in New Hampshire;
- EverPower's 126-MW Cassadaga wind project in Chautauqua County in western New York; and
- Two 20-MW solar projects from RES Americas, one in Connecticut and one in Rhode Island.

In an updated timeline, the states want electric distribution utilities to enter contracts with the bidders by Jan. 15, which would be filed with the states' regulators by March 1.

The states ended up focusing on renewable generation projects and bypassed transmission. Two high-profile projects that would have imported Canadian hydropower did not make the cut: Eversource Energy's Northern Pass, which is planned to run through New Hampshire; and Anbaric Transmission's Vermont Green Line, which would have connected wind power in New York, combined with Canadian hydropower, and be buried under Lake Champlain and underground in Vermont.

Several transmission projects that would move wind power from Maine to load centers farther south were also rejected in the RFP. Eversource's 600-MW Clean Energy Connect between Massachusetts and New York did not advance.

"We are pleased with the key approvals the project continues to receive and look forward to participating in the April solicitation for large-scale hydroelectricity," Bill Quinlan, president of Eversource New Hampshire Operations, said in a statement. "The region's energy landscape is shifting quickly. Northern Pass, with its 1,090 MW of clean hydropower, and permitting well underway on both sides of the border, is in a strong position to play an important role in helping the region achieve a cleaner energy future."

Massachusetts will issue its own RFP next year to procure renewable energy, which would give Northern Pass, Clean Energy Connect and others another chance. (See *Massachusetts Bill Boosts Offshore Wind, Canadian Hydro*.)

SEBANE

ISO-NE News

ISO-NE Auction Rehearing Requests Denied

By William Opalka

FERC on Thursday rejected rehearing requests by a generator and a utility workers union on its order accepting the results of ISO-NE's 10th Forward Capacity Auction (ER16-1041-001).

Dominion Resources challenged the auction results over ISO-NE's exclusion of a capacity increase at its Providence, R.I., generating plant. The commission had rejected the company's complaint in a parallel proceeding Oct. 20. "Dominion's instant rehearing request does not raise any issues that are new to this proceeding or that were not already addressed in the order denying rehearing," FERC wrote. (See *FERC Again Rejects Dominion Bid for ISO-NE Auction Resettlement*.)

The Utility Workers Union of America said the auction should be voided because the slated-for-closure Brayton Point station, whose workers it represents, has been withheld from the past three FCAs. FERC has repeatedly dismissed those complaints. (See *FERC Again Rebuffs Brayton Point Union*.)

Rehearing Denied on Gas Pipeline Subsidies

Separately, the commission denied a rehearing request by Algonquin Gas Transmission over ratepayer subsidies for the same reason it rejected complaints by Public Service Enterprise Group and NextEra Energy (EL16-93-001).

PSEG and NextEra alleged that the New England states' effort to expand natural gas capacity with electric ratepayer subsidies was an attempt to suppress power prices. FERC dismissed that complaint on procedural grounds in August, saying the companies' concerns were "speculative and unsupported." (See "Access Northeast Complaint Dismissed," *FERC Rejects Capacity Release Exemption for NE Gas Generators*.)

Algonquin sought rehearing so the commission would dismiss that case on the merits, saying the procedural dismissal left open the possibility that NextEra and PSEG could "continue their troubling delay tactics."

FERC demurred, saying the Federal Power Act allows rehearing only for those "aggrieved" by a commission order. "Here, the Aug. 31 order dismissed the complaint, which was the end result advocated by Algonquin," FERC said.

"The commission is not obligated to reach the merits of a case when it can be decided on procedural grounds. Administrative economy concerns are particularly acute where, as here, the facts are in flux and the record before the commission may be incomplete."

Brayton Point

MISO NEWS

MISO Agrees to Implement Most of IMM's Recommendations

By Amanda Durish Cook

MISO said it generally agrees with the recommendations its Independent Marker Monitor laid out in its 2015 State of the Market report, but the RTO won't implement a few recommendations and wants additional analysis on some others.

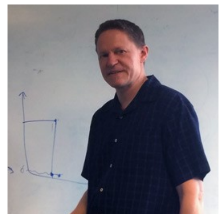
On a conference call of the Market Committee of the Board of Directors on Oct. 24, MISO said there is only a "minority of problems identified where [it] believes additional analysis is necessary to confirm [the] problem or to identify alternative solutions."

Under MISO's Tariff, the RTO has 120 days to respond to the Monitor's recommendations.

Software Changes Required

MISO Executive Director of Market Design Jeff Bladen said the RTO is working on expanding eligibility for online units to set prices in extended locational marginal pricing (ELMP), but changes to the software would be difficult and it wanted to focus on other Market Roadmap projects first. However, MISO still breaks with the Monitor on suspending offline pricing in ELMP. (See "MISO to Expand ELMP Price Setting, but not to IMM's Specs," MISO Market Subcommittee Briefs.)

Bladen said implementing the Monitor's full suggestion would require a complex software modification. "There are no simple code changes to the software at this point. It certainly isn't a one-day change," he said.


Patton

Market Monitor David Patton said the difficult software change stems from software vendors "hard coding" software where it cannot be opened later to expand design parameters.

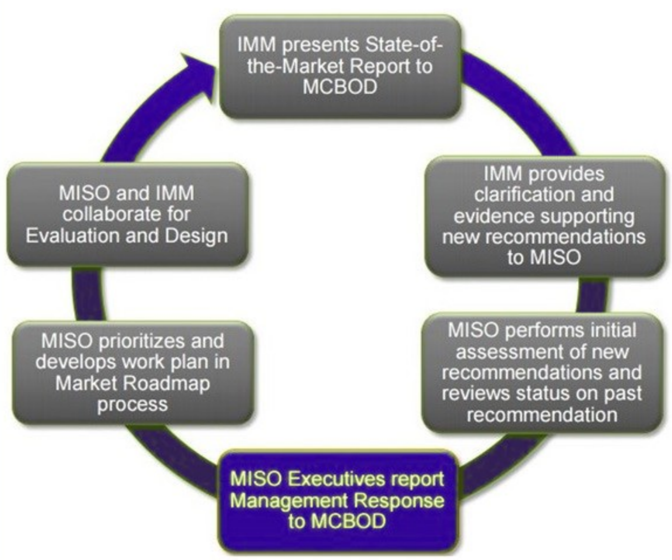
Bladen said although it agrees with the Monitor that it should implement firm capacity delivery procedures with PJM, MISO has been unable to move the solution through the two-party approval process because of resistance from PJM earlier this year and has put its proposed solution on hold. (See "Ready for Pseudo-Tie Switchover," MISO/PJM Joint and Common Market Meeting Briefs.)

"It's PJM that requires resources external to PJM to be pseudo-tied," Patton agreed. He said he and MISO are considering asking FERC to open a Section 206 proceeding against PJM to force a change in its Tariff.

'Weaponizing' FERC Filing

MISO Director Michael Curran said he would rather not build a relationship with PJM by "provoking" them with a 206 proceeding and cautioned against "weaponizing" FERC filings. CEO John Bear said MISO is developing alternatives to firm capacity procedures to present to PJM.

Bladen said the Monitor's advice to improve the modeling of transmission constraints in the Planning Resource Auction was not prioritized by stakeholders as a key concern, but MISO would work on scoping a study.



Process to address IMM State of the Market recommendations | *MISO*

The RTO also said it agreed with the expansion of temperature-adjusted and short-term emergency ratings for transmission facilities and will work with its transmission owners on improvements.

However, MISO is unlikely to increase physical withholding mitigation measures in the PRA by addressing uneconomic retirements. The RTO said the concept of uneconomic retirements itself is a problematic, as such instances would be difficult to determine.

Patton countered that the problem could crop up when a large generator clearly retires to give affiliates a higher clearing price. Bladen said the threat of an entity's permanent loss of injection rights if it is found to be gaming the market is "sufficient deterrent" to such retirements. He said MISO is working on a suggestion from 2013 to subject suspended resources to withholding rules, but he didn't see the need to include retiring generation.

However, MISO has committed to expanding withholding mitigation in the PRA by recognizing affiliates' connections. Bladen said MISO and Patton will discuss the issue with stakeholders. "We think it's important to look at the affiliate nature of resources and examine them for physical withholding," Bladen said.

On the other hand, MISO sees gray areas around a few of Patton's recommendations. MISO says it is awaiting further details from the Monitor on how to improve the modeling of transmission constraints in the PRA and is looking for changes that can be achieved in the near term.

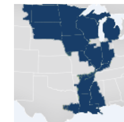
Transfer Constraint

MISO took a similar wait-and-see stance on Patton's suggestion to increase the transfer constraint between the RTO's South and North regions in the PRA. The RTO said it is holding stakeholder discussions and has support for a study to examine the benefits of developing its own transmission to link the interfaces, as an alternative to SPP's transmission. (See *MISO Proposes Study to Measure Benefits of New North-South Tx*.)

The study will be rolled into other analyses as part of MISO's 2017 Transmission Expansion Plan. MISO said the annual cost to

Continued on page 15

MISO NEWS



MISO Adds 3 New Board Members, Posts Staff Incentive Plan

By Amanda Durish Cook

MISO membership voting results confirmed three new Board of Directors members.

The new directors, announced at MISO's Oct. 25 Informational Forum, are former ERCOT CEO H.B. "Trip" Doggett, former Calvert Investments CEO Barbara Krumsiek and Todd Raba, who is leaving Twenty First Century Utilities and has served as CEO of both GridPoint and Berkshire Hathaway's Johns Manville. The three were selected by MISO's Nominating Committee in September from a pool of about 30 applicants. (See "MISO Membership Voting on 3 New Board Members," *MISO Board of Directors Briefs*.) The trio begin three-year terms Jan. 1, after Board Chair Judy Walsh and directors Michael Evans and Paul Feldman reach MISO's term limit.

Director Michael Curran welcomed the new members in a press release. "We are pleased to have their experience on the board to help ensure MISO remains nimble and on the forefront of the ever-evolving energy industry."

MISO Deputy General Counsel Eric Stephens said 35% of the RTO's members cast votes in the election, which was held from Sept. 16 to Oct. 24; a 25% participation rate was needed to reach a quorum. Stephens said MISO had the election independently certified to verify the results.

MISO CEO John Bear said the RTO's entirely electronic voting platform, implemented a few years ago, ensured a smoother voting process.

MISO Incentive Plan up for Stakeholder Inspection

Meanwhile, MISO and its current board posted a first draft of its short-term incentive plan for stakeholder review through Nov. 21. The plan, revealed at the Oct. 25 Human Resources Committee of the Board of Directors, outlines the board's discretionary bonus for MISO staff based on nine weighted performance metrics.

Among the targets staff must meet to qualify for the incentive pay are:

- Keeping spending within 2.5% of the annual operating budget and 8% of the capital budget;
- At least 94% "market funding efficiency," a measure of the alignment between financial transmission rights and the day-ahead and real-time energy markets that indicates whether transmission capacity was oversold or undersold in the forward markets;
- Information technology availability: no more than eight unplanned incidents exceeding one hour of service per year;
- 94% unit commitment efficiency, a measure of how effectively MISO commits generation in its forward and intra-day processes to meet demand and mitigate constraints; and
- Minimal FERC and NERC reliability violations.

"One of the reasons I think this has worked is because we're pretty hard graders on ourselves," Bear said.

MISO Agrees to Implement Most of IMM's Recommendations

Continued from page 14

maintain constraints under the SPP settlement can be as much as $38 million.

The RTO also has mixed feelings about modeling its voltage and local reliability requirements in the day-ahead market, saying it already models the requirement but doesn't include it in the day-ahead market. However, it said it would discuss potential advantages of an automated market process with the Monitor

Bladen said it will take five to seven years to implement all of the 2015 solutions MISO agrees with, calling the timeframe in line with the RTO's "robust stakeholder process."

Bladen also said all recommendations made prior to 2011 have been resolved. It takes MISO an average of 2.3 years to close out suggestions, according to the RTO.

Patton said implementation of software fixes for his recommendations are sometimes slowed by difficulty scheduling work with MISO's software vendors or getting the attention of RTO executives responsible for multiple market improvements.

MISO NEWS

MISO Predicts Adequate Winter Reserve Margin

By Amanda Durish Cook

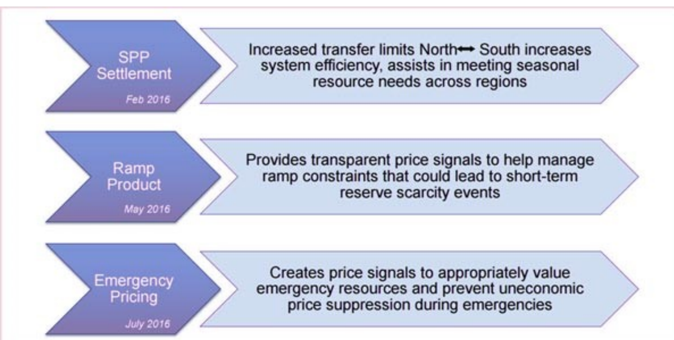
MISO predicts a 28.4 to 37.5% reserve margin for the winter, about double its minimum of 15.2%.

Regardless of the ample supply, the RTO will continue providing monthly tests and workshops for stakeholders to prepare for "all winter can dish out this year," MISO Executive Director of Strategy Shawn McFarlane said at the Oct. 24 Markets Committee of the Board of Directors meeting.

McFarlane said abundant supplies are the result of increased North-South transfer limits obtained in the RTO's settlement with SPP; the rollout of its ramp product; and improved emergency pricing after the introduction of emergency pricing floors in July.

He also pointed to MISO's improved gas-electric coordination, prompting Director Baljit Dail to ask how the RTO would respond in a repeat of 2014's polar vortex.

Todd Ramey, vice president of system operations and market services, said MISO now has better communication with pipeline operators, and its control room operators can now see when pipes are constrained through reports and map displays. "We have a better understanding about fuel supply impacts to generators in the footprint," Ramey said.



MISO's three keys to winter readiness | *MISO*

Senior Director of Regional Operations David Zwergel told the Informational Forum on Oct. 25 that MISO is prepared to handle forced generation outages and fuel limitations. "We will continue to proactively prepare for any extreme conditions that may arise," Zwergel said.

Zwergel

MISO is following National Oceanic and Atmospheric Administration forecasts, which predict a warmer- and drier-than-usual winter in MISO South and colder-than-usual temperatures in MISO North.

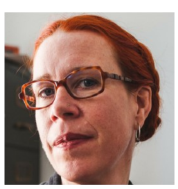
Jeff Bladen, executive director of market services, said MISO filed a waiver with FERC on Sept. 28 to allow generators to recover verifiable offers in excess of the $1,000/MWh price cap. The filing marks the third year MISO has used the temporary waiver approach while it waits on a permanent offer cap rule from FERC. (See "3rd Run for Energy Offer Cap Interim Solution," *MISO Market Subcommittee Briefs*.)

Bladen also said there was an increase in planned outages last month in preparation for the winter season, averaging 12.5 GW in September compared to 5.1 GW in August.

Anthropologist Discusses Cultural Attitudes Toward Grid with MISO

By Amanda Durish Cook

CARMEL, Ind. — MISO presented a different perspective at its Oct. 25 Informational Forum, inviting cultural anthropologist Gretchen Bakke to talk about shifting attitudes toward electrical infrastructure.



Bakke

Bakke, assistant professor of anthropology at McGill University in Montreal and author of "The Grid: The Fraying Wires Between Americans and Our Energy Future," has studied failing systems in Cuba, the Soviet Union and Yugoslavia. She said the grid is as much of a cultural creation as a technical one. "As such, it moves with us. We think of it as solid and rebar, [towers] and copper, but the truth is it grows with us."

The current grid is a poor fit for a new generation of customers who want carbon-free electricity, Bakke said. The grid's reliability becomes more "fragile" with increasing investment in intermittent renewables, and Bakke calls for "a serious reimagination of the grid" beyond simply repairing aging infrastructure.

"People right now are moving against the grid," Bakke said. She pointed to the development of phones with ultra-low power transistors that can function for years without a battery, Elon Musk's self-driving cars, Iceland digging a 3-mile hole into magma to tap geothermal power and Democratic presidential candidate Hillary Clinton's push for 500 million solar panels in the U.S.

Bakke said regulators have made electricity so reliable and so cheap that consumers can "unwittingly" ignore it. Consumers tend to think that energy storage is a panacea, forgetting that producing batteries causes pollution and batteries cannot be charged by renewable power alone, she said.

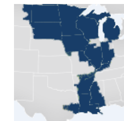
"The way that solar PV has been presented is as this free power source that you can get money back on. And that contributes to this 21st century [attitude]," Bakke said.

Customers' desire for more local distributed energy resources are at odds with their preference for renewable generation, which often requires tapping remote sources via transmission.

"All of these dreams rely on a deep ignorance of infrastructure," Bakke said. "It's this upswing in wanting to eat food grown from a local farmer," Bakke explained. "Iowa wind is fine to power the Twin Cities."

Bakke said MISO stakeholders are the edge of the consumer "push and pull," but she said resource owners should nevertheless pay attention to what consumers are demanding.

MISO NEWS



Advisory Committee Briefs

MISO Predicts Budget Increase in 2017, Introduces 5-Year Business Plan

MISO is requesting a 4% increase in operating expenses for 2017 while moving away from a one-year forecast in favor of a five-year business plan.

The requested increase will bring the 2017 operating budget to $289.6 million, said Mitch Myhre, chair of the MISO Finance Subcommittee, who presented the budget to the Advisory Committee during an Oct. 26 conference call.

The operating budget includes:

- $229.6 million in "base" spending;
- $51 million in structural expenses (including amortization of membership integration costs, depreciation of cybersecurity investments and infrastructure upgrades and funding of the Independent Market Monitor and Organization of MISO States); and
- $9 million for strategic initiatives, including the Competitive Retail Solution, seasonal and locational capacity, improving gas modeling, and automatic generation control enhancements.

MISO forecasts it will end 2016 with operating expenses of $225 million — its budgeted amount — to $227.3 million, which would be 1% over budget.

Myhre said MISO's new five-year budget approach will be an "evolving, rolling" budget. The RTO is predicting a 1.9% compound annual growth rate for the next five years. The subcommittee and MISO staff are still working on the details of the five-year plan, Myhre added.

The plan projects an identical $289.6 million spend in 2018. In 2019, the figure increases to $293.5 million, then $299.5 million in 2020 and $306.7 million in 2021. In every budgeted year, MISO plans to spend exactly as much as it brings in.

MISO also is requesting a 2017 capital budget of $29.9 million — a drop from 2016's $31 million — and an average capital spend of $32.9 million over the next five years.

However, the RTO said it might request out-of-cycle budget approvals in 2017 for initiatives in the works, including the construction of a new security operations center, more software quality control, improved server utilization, positioning an off-duty police officer at MISO control sites and insourcing some outside contracts. For those possible expenses, the Finance Subcommittee recommended MISO create business cases to present to the appropriate stakeholder groups.

American Electric Power's Kent Feliks thanked Myhre and MISO for the budget work. "A lot of this work isn't very exciting, but it's vital to MISO," he said.

Final approval of the 2017 budget and adoption of the five-year spending plan will take place at the Board of Directors meeting in December.

AC to Approve One of Two Sets of 2017 Priorities

The Advisory Committee will adopt one of two revised sets of priorities for 2017, choosing between one that is a slight revision of existing priorities and another that takes its cues from subcommittee mission statements.

Gary Mathis, representing MISO's Transmission-Dependent Utility sector, said the committee's approved priorities for this year are unclear and hard to remember. Mathis said the subcommittees' mission statements could become the committee's overarching priorities themselves. He presented five proposed priorities: implementing best planning practices; preserving and enhancing reliability; improving market efficiency; ensuring resource adequacy; and ensuring equitable cost allocation.

Advisory Committee Chair Audrey Penner presented the alternative, which was slightly changed from the 2016 priorities list. It moves the gas-electric coordination priority under a broader environmental policy and portfolio evolution priority. A strategic guidance priority was added in its place that includes hot topic discussions and a broad current issues subcategory. (See "Committee Endorses 5 Final Priorities," *MISO Advisory Committee Briefs*.)

Penner said both priority documents capture "the essence of what the priorities should be."

"A lot of this work isn't very exciting, but it's vital to MISO."

Kent Feliks, AEP

The committee will vote to adopt one of the two approaches at its December meeting. Penner said committee leadership hopes to keep the committee's priorities on the books for multiple years while performing six-month "check-ins" to assess their continued relevance.

AC's Strategic Session Prompts Possible 'Hot Topic' Change

Advisory Committee members noticed that the committee spent quite a bit of time on this year's stakeholder redesign and said it looked forward to paying more attention to other issues in 2017, reported Penner, who gave an overview on the committee's strategic planning session held at the end of September in San Antonio.

Penner also said the committee is looking to change its hot topic forum back to its original format, with wider stakeholder participation in drafting questions, instead of MISO facilitating the discussion. Director of External Affairs Kari Bennett said the RTO had no problem with re-establishing the old arrangement.

The Advisory Committee is considering holding hot topic conversations in 2017 that focus on transmission, including cost allocation, pseudo-ties and the competitive bidding process. Penner said the committee would solicit votes by email to its voting sectors to decide on a March topic. She added that the committee might suggest MISO hold an educational session prior to sectors submitting their written positions on hot topic subjects.

Penner also urged stakeholders to attend a Nov. 3 Stakeholder Governance Guide workshop. During the Oct. 26 Steering Committee conference call, Chair Tia Elliott said agenda items could include conference call logistics; meeting procedure education; an overview on Robert's Rules of Order; criteria for establishing closed groups; and the creation of a definition for task teams with a process for creating and retiring them.

— Amanda Durish Cook

NYISO NEWS

NYISO OKs Capacity Export Fix over Generators' Opposition

By William Opalka

RENSSELAER, N.Y. — Over objections by generators, the NYISO Management Committee on Wednesday approved a temporary rule change to partially insulate consumers from sharply higher capacity prices as a result of exports from constrained zones.

The committee approved its interim solution with 63% of the vote.

The proposed rule change is in response to FERC's Oct. 17 order accepting ISO-NE's changes to its annual reconfiguration auctions for its forward capacity market. NYISO tried and failed to get FERC to delay the changes for a year, saying it needed the time to amend its rules to ensure exports out of an import-constrained zone didn't penalize ratepayers. (See *FERC Sides with ISO-NE in Capacity Dispute with NYISO*.)

FERC's ruling allows Castleton Commodities International's 1,242-MW Roseton 1 generator, located 43 miles north of New York City in NYISO's capacity import-constrained G-J locality, to supply 511 MW of its capacity to ISO-NE beginning next June for the 2017/18 delivery year.

Current New York rules treat exported capacity the same as if the plant supplying it had been retired or mothballed.

"The NYISO's objective in formulating our proposed market design has been to eliminate inefficient pricing outcomes due to exports from import-constrained localities," Emilie Nelson, vice president of market operations, said at the meeting. "Our overarching goal is to send effective short- and long-term market signals that incent investment and retain resources where they are needed without imposing undue consumer impacts."

Generators at the meeting complained that the changes endorsed by the committee — particularly an amendment offered by transmission owners — cap capacity prices without justification. In an amended motion approved by the committee, those payments have been capped at 20% of what the generators would be paid under a formula devised by NYISO staff.

"I see this just as a vote for lower prices because I see no technological background behind it," said Mark Younger, who represents several generators.

Supporters of the interim rule change did not challenge that characterization. "While this is not a perfect solution, this gets us to where we need to be in the short term," said Kevin Hunt, who represents large industrial customers and New York City.

ISO officials said they will promise in their Section 205 filing seeking FERC approval of the rule change to continue work on the issue in its stakeholder groups.

Under a complex formula by NYISO staff based on power flow analysis, for each megawatt committed to New England, capacity prices in the constrained zones in the Lower Hudson Valley would go up by almost 48%.

The "locality exchange factor" incorporates base case data from the most recent reliability planning process to determine the amount of generation from the "Rest of State" areas outside of the constrained Hudson Valley that can be brought into the constraint area. The LE factors will be calculated annually.

The LE factor for the coming year is 47.8%, which means a price signal to replace 52.2% of the exports to ISO-NE is efficient, NYISO says. In other words, 52.2% of the exports can be replaced by resources from within the same locality, but 47.8% must be replaced by capacity resources from the Rest of State.

Under the amendment offered by TOs, the capacity cost increase borne by consumers would be capped at only 20% of the cost the LE factor would have imposed.

NYISO estimates that while prices will still rise for in-state customers because of the exports, the rule change will reduce the increase by at least $144 million.

Independent Market Monitor David Patton had identified the problem in his 2015 State of the Market report, recommending that NYISO act quickly to recognize the reliability value of generators in import-constrained zones to avoid a rise in capacity prices.

NYPSC Vision for DER: From Net Metering to 'Value Stack'

Continued from page 2

under REV," the report continues. "As a result, investment in new DER capacity is often made without regard to how the design, siting and operation of those resources can maximize benefits to the electricity system overall."

Failing to properly identify and compensate DERs for their value limits incentives for adding technologies such as smart inverters.

"At low levels of DER penetration, the economic inefficiencies resulting from the incomplete price signals embedded in NEM are less consequential, but as adoption increases, these potential misalignments — and the uneconomic effects associated with them — will increase," the report said.

The LMP applied in the wholesale markets does not separate ancillary services, load shifting and environmental and performance benefits "that are essential design features of a fully optimized bidirectional power system and decarbonized network," it said.

Collaborative

A collaborative effort involving utilities, consumer advocates, environmentalists, solar and DER providers that started last December was the first step in providing input for the new market framework. The report also builds on several REV-related efforts including the development of a benefit-cost analysis framework and utility distributed system implementation plans.

"Today, the customer side of the grid represents an enormous and largely untapped resource to optimize value throughout the electricity system. REV will establish markets so that customers and third parties can be active participants, to achieve dynamic energy management on a systemwide scale, resulting in a more efficient and secure electric system, including better utilization of bulk generation and transmission resources," the report says.

Advertisement

PJM News

MRC/MC Briefs

Manual 14 Changes Sail Through

WILMINGTON, Del. — Both manual revisions on the agenda won Markets and Reliability Committee approval by acclimation without objection.

The revisions to Manual 14A: Generation and Transmission Interconnection Process were recommended by the Earlier Queue Submittal Task Force. They include changes to the assignment of queue priority; timing, including scheduling of deficiency reviews; criteria for inclusion in feasibility studies; and fee structures.

The revisions to Manual 14C: Generation & Transmission Interconnection Facility Construction set technical standards for Order 1000 projects.

IRM Study Approved but Criticized for Lack of Winter Analysis

The MRC endorsed the 2016 Installed Reserve Margin study results. However, Tom Rutigliano of Achieving Equilibrium, who consults for demand response provider WeatherBug Home, announced his abstention because the study doesn't make any indications about winter reliability. (See *No Consensus Among PJM Stakeholders on Seasonal Resources*.)

Credit Policy Changes Approved

The MRC endorsed proposed clarifications to the credit policy in Tariff Attachment Q that reorganize provisions and make five minor changes to them, none of which affects credit requirements. (See "Attachment Q Modified; Credit Requirements Unaffected," *PJM Market Implementation Committee Briefs*.)

MIC Charter Changes Approved

The MRC approved the updated Market Implementation Committee charter, which removes references to working groups. (See "'Working Groups' Removed from MIC Charter," *PJM Market Implementation Committee Briefs*.)

Dominion Retiring Bath County Thermal SPS

A special protection scheme Dominion Resources used to minimize N-1 overloads and allow for a higher pond level at a pumped storage facility is no longer needed thanks to a number of regional system upgrades.

Dominion plans to retire the Bath County thermal SPS by Dec. 1, but it says the stability SPS there will remain in place.

Tariff Changes Pass Members Committee Easily

The Members Committee endorsed by acclimation two sets of Tariff changes:

A Tariff revision authorizing use of a straight-line offer curve for selling back excess capacity in February's third incremental auction for the 2017/18 delivery year. (See "Proposal Chosen for Capacity Release," *PJM Markets and Reliability and Members Committees Briefs*.)

Operating Agreement and Tariff revisions developed by the Metering Task Force to close gaps in understanding between staff and members on metering rules. (See "No Objections to Metering Revisions," *PJM Markets and Reliability and Members Committees Briefs*.)

— Rory D. Sweeney

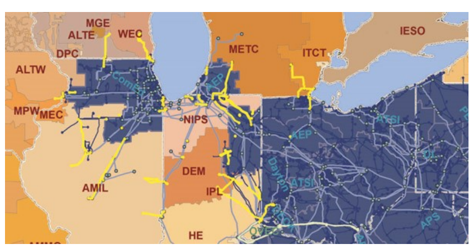
FERC OKs PJM, MISO Order 1000 Interregional Filing; Denies Rehearing

By Rory D. Sweeney

FERC last week conditionally approved revisions to the MISO-PJM Joint Operating Agreement on cost allocation for cross-seam transmission projects, while denying rehearing requests from PJM and the RTOs' transmission owners (ER13-1944, *et al.*).

In rejecting the rehearing requests, the commission said the grid operators and TOs chose the avoided-cost-only method for allocating the costs of such projects, so any issues that method creates should be addressed within the operators' stakeholder processes.

In a previous filing, PJM and MISO settled on a cost-allocation method that is based on how much the cross-border project saves each grid operator on regional projects it supplants. The commission, however, said the method didn't consider regional projects that have already been selected, nor did it explain how it would measure if an interregional project is more efficient or cost effective than a regional one.



PJM-MISO tie lines

MISO's TOs asked for the rehearing because they were concerned that displacing projects that had already been selected wouldn't allow them to recover millions of dollars in development costs incurred on those projects prior to them being abandoned. MISO's Tariff, they noted, does not explicitly provide for such recovery.

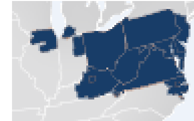
"To the extent that MISO transmission owners are requesting that the commission mandate full cost recovery for transmission projects selected in a regional transmission plan but displaced by an interregional transmission project, we reject their request as outside the scope of the Order No. 1000 compliance proceedings," the commission said.

"If MISO transmission owners continue to believe that these costs are not treated appropriately under MISO's Tariff, they may pursue changes through the MISO stakeholder process and make a filing to amend the MISO Tariff or else file a complaint with the commission pursuant to [Federal Power Act] Section 206."

FERC approved portions of the grid operators' compliance filings, including how projects can be categorized, but it ordered additional changes to eliminate some inconsistencies. (See "MISO Order 1000 Compliance," *MISO Planning Advisory Committees Briefs*.)

MISO and PJM have 30 days to make additional filings to fully comply with the order.

PJM NEWS



Crafters of Pa.'s Deregulation Law Look Back After 20 Years

By Peter Key

HERSHEY, Pa. — One of the hoariest clichés about legislating is that there are two things no one wants to see get made: laws and sausage.

But on Friday, participants in drafting the bill that brought competitive power generation to Pennsylvania reminisced about the experience as enthusiastically as if they were biting into Lebanon bologna.

The people doing the reminiscing were on one of the panels in a two-day celebration of the 1996 Electricity Generation Customer Choice and Competition Act's 20th anniversary, which made the Keystone State one of the first in the nation to embrace retail choice.

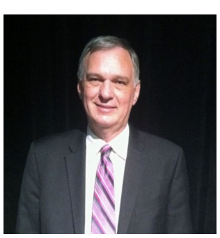
The conference was put on by the consulting firm of John Hanger, one of the architects of the state's introduction of competition as a member of the Pennsylvania Public Utility Commission.

Joining Hanger on the panel were former state Sen. David Brightbill, who helped craft the law; Sonny Popowsky, Pennsylvania's long-time consumer advocate, now retired; and former PUC and FERC Commissioner Nora Mead Brownell, who helped implement the law.

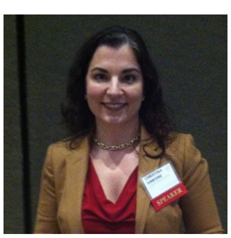
Brightbill remembered how Hanger helped lay the groundwork for the law, which had strong support from energy-intensive industrial customers.

Popowsky said one thing that people tried but failed to get into the law was a provision requiring utilities to divest their generation assets or put them in separate companies. That, he said, turned out to be moot, as the utilities chose to do that anyway.

So that all the parties that would be affected by the law could have a say in crafting it, they agreed to press for only what they needed to be in it, not what they wanted to be in it, the panelists recalled. Even so, at the last minute, someone brought up possible amendments, causing great consternation for Hanger because the law had been put together so carefully that he was convinced any changes to it would cause it to fall apart.



Hanger



Simeone

Impact

So what's been the impact of Pennsylvania's restructuring?

A study funded by the University of Pennsylvania's Kleinman Center for Energy Policy — and authored by Hanger and Christina Simeone, the center's director of policy and external affairs — concluded that the law allowed consumers to benefit from the reduced power prices caused by the natural gas boom.

From 1996 to 2014, output from natural gas-fired generation in Pennsylvania grew 26% while output from coal-fired generation dropped 17%.

The report found that the retail price of electricity in Pennsylvania fell from 15% above the national average prior to deregulation to 0.1% below the national average last year.

Had Pennsylvania not changed the law, the report also pointed out, consumers might still be paying power rates based on valuations assigned to power plants by the PUC, rather than rates based on the market cost of generating power. Under that scenario, electricity consumers would have seen much less benefit from low natural gas prices, while coal-fired and nuclear-powered generation plants that were valued decades ago wouldn't be the drag on their owners' profits that they are today.

By introducing competition, the law has allowed low natural gas prices to flow through to consumers, Hanger said. "That's what we wanted to accomplish."

Although the restructuring law was passed in 1996, most consumers wouldn't have much incentive to shop for power providers for another 15 years. That was because the utilities agreed to have their distribution subsidiaries cap the rates at which those subsidiaries offered power in exchange for being allowed to recover some of their "stranded costs" — the difference between their generation plants' book value before deregulation and their market value after. Different utilities had their caps come off at different times, but all were gone by the start of 2011.

Since the rate caps have come off, the electric distribution companies (EDCs) have remained default power providers for customers who don't want to shop for a generation provider, buying power on the wholesale market and reselling it at no profit to those customers.

Shoppers vs. Default Customers

The report looked at how power customers that shopped for a generation provider did compared to those that continued as default customers. It concluded that retail electricity rates for commercial and industrial customers that shopped for power were generally lower than the same rates for commercial and industrial customers that bought power from their distribution company.

But the report found that the reverse was true for residential customers, with rates for those who shopped for power being higher than the rates for those who bought it from their distribution company.

Despite that, Popowsky, the former consumer advocate, said that residential consumers have benefited from the law because even the default prices offered by the distribution utilities are the result of competition among generation providers. "One hundred percent [of consumers] are getting competitive generation," he said.

The study found that residential distribution rates prices for all but one EDC increased faster than inflation from 1996 through 2016, with the increases exceeding generation and transmission savings for some utilities. Distribution rates remain under cost-of-service regulation by the PUC.

Having distribution utilities serve as default power providers for customers that don't want to shop for a generation provider has proved controversial. There were calls to eliminate having distribution companies serve as default power providers and forcing all electricity customers to shop for generation providers. But the proposals lost favor after the 2014 polar vortex, when many customers who chose competitive suppliers — unaware they were paying spot

Continued on page 22

PJM NEWS

Crafters of Pa.'s Deregulation Law Look Back After 20 Years

Continued from page 21

prices — got socked with huge bills.

The report said it couldn't conclude why default residential rates were lower than power-shopping residential rates. Competitive suppliers, it said, argue that they provide additional attributes — such as renewable power, discounts and incentives — for which consumers are willing to pay a premium. Default service supporters, the report said, argue that higher retail supplier costs and greater volatility make rates for shoppers higher than default rates.

While residential customers' savings have been less than those seen by commercial and industrial customers, the Retail Energy Supply Association said that is because residential customers have been less likely to shop.

The report found that 22 to 46% of residential customers are shopping for power suppliers, depending on their distribution company. In contrast, 30 to 50% of commercial customers and more than 80% of industrial customers abandoned their distribution companies.

"The appropriate comparison for residential benefits is to examine available competitive offers that not all consumers take advantage of," RESA said in a press release. "The lowest-available 12-month fixed-price offers represent more than $314 million in potential annual savings to consumers if all remaining customers switched to these offers."

RESA called for Pennsylvania to do more to promote competition. It also said the state should consider removing regulated utilities from providing default service, leaving them to focus only on distribution and transmission. "This approach has worked well in Texas, the state widely recognized to have the most robust competitive electricity market," the group said.

Other Studies

There's no shortage of opinions on whether competition has been a good thing for consumers.

A 2015 study by the University of California Berkeley concluded that competition had improved power plant efficiency and grid coordination but that falling gas prices had a bigger impact on rates.

A study released in February by the Electric Markets Research Foundation concluded that retail choice has done little for retail consumers. The foundation, whose website does not disclose its funders, has ties to Hunton and Williams, a D.C. law firm that has led utility challenges to EPA clean air regulations. Its 2013 and 2014 tax returns listed its president as Bruce Edelston, a former Southern Co. official who rejoined the company this year as vice president of energy policy.

Research by the Pennsylvania Utility Law Project found that customers enrolled in low-income assistance programs paid more on average with competitive power suppliers than they would had they stayed with their utility's standard offer. "Competitive markets are bad for poor people," PULP Executive Director Patrick M. Cicero told *The Philadelphia Inquirer*.

Renewed Questioning

The 20th anniversary comes at a time of renewed questioning of electric regulation.

Pennsylvania followed shortly behind California in enacting competition, the beginning of a wave that would sweep over almost half of the nation.

California's 2000-2001 energy crisis, and revelations that Enron and other power traders had manipulated the market, brought that wave to a halt. At the peak of the movement, 22 states and D.C. had or were moving toward competitive generation markets. That number is now 14 states and the district.

At least three competitive states — New York, Ohio and Illinois — have approved or are considering subsidies for fossil and nuclear generators losing money because of cheap natural gas and renewables. Utilities in Ohio are also pushing a partial return to regulation.

Constellation Energy CEO Joseph Nigro made a pitch for nuclear subsidies in a keynote address on the second day of the conference. Constellation is a subsidiary of Exelon, owner of the country's largest fleet of nuclear power plants.

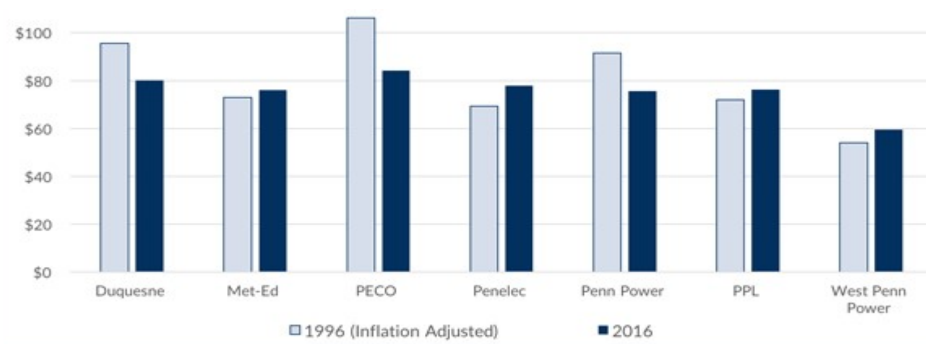
In addition to promoting the environmental benefits of nuclear power, Nigro talked about how Constellation, Exelon's competitive energy subsidiary, is responding to consumers' demands for adaptability, reliability and sustainability.

"We believe that a culture of innovation must exist at every level of the company," he said.

Nuclear subsidies also came up in another panel discussion on several recent Supreme Court rulings on jurisdictional fights between state and federal regulators.

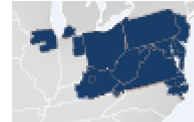
One of the decisions discussed was the court's *Hughes v. Talen* ruling that a Maryland program designed to subsidize new generation facilities infringed on FERC jurisdiction.

That ruling should enable opponents of New York's nuclear subsidies to prevail in their federal court suit, said Abe Silverman, a counsel for NRG Energy, one of the plaintiffs. (See *Federal Suit Challenges NY Nuclear Subsidies*.)



Bundled bills for residential customers of Duquesne Light, PECO Energy and Penn Power were 16 to 21% lower in 2016 than inflation-adjusted bills for 1996. Ratepayers in some other EDCs saw bills rise as distribution rate increases exceeded generation and transmission savings. Chart shows monthly bill for customer using 500 kWh. | *A Case Study of Electric Competition Results in Pennsylvania, Kleinman Center for Energy Policy*

PJM NEWS



No End in Sight for PJM Capacity Market Changes

Continued from page 1

public-policy actions that might upset the delicately balanced CP market. (See *Review of PJM Capacity Market Put on Hold*.)

However, John Farber of the Delaware Public Service Commission urged that the issue not be framed that way. "The existential threat is not with states, but possibly [to] customers who have to pay the eventual costs," he said.

Some stakeholders pushed for adding more topics to those listed, while others said they opposed broadening the scope. Susan Bruce, an attorney who represents the PJM Industrial Customer Coalition, said the proposal needs to be broad enough to cover more than just capacity market impacts but narrow to the extent that PJMICC isn't interested in talking about alternatives to RPM.

"I appreciate the dilemma," she said.

EnerNOC's Katie Guerry requested that the proposal's language be more accommodating toward change rather than defensive. "Why don't we set up a more productive process where we can work toward solutions?" she asked.

Both Bruce and Exelon's Jason Barker said they would attempt to edit the proposal into something they could support, but "I'm not sure how to address that or to modify the current statement," Barker conceded.

"What I'm hearing today is, 'let's re-broaden the discussion, at least to start.' … I don't understand what people want. Do they want to have a broad discussion and narrow it?" asked Jeff Whitehead, whose Direct Energy is a sponsor of the proposal. "It's a pretty big ask of this group to have us find the right scope of this discussion before we start the work. One of the main issues here is defining what are these public policies that impact the wholesale market."

Tatum said his goal is to find the CP version of the Serenity Prayer: a construct that can change what's within its authority to change, accept what it can't change and know the difference.

The lack of consensus caused frustration among the proposal's sponsors. PJM's Dave Anders, the committee's secretary, suggested a separate informational meeting on the topic, but none of the sponsors actively supported the idea.

"I personally don't see a need for an informational meeting," said Steve Lieberman of Old Dominion Electric Cooperative. He said it would be "surprising" if there were new perspectives on the proposal than the ones that had already spoken up.

"Frankly, if we don't want to talk about this, let's stop talking about it," Whitehead said.

Carl Johnson of the PJM Public Power Coalition, which also sponsored the proposal, reminded everyone that ignoring the issue wouldn't make it go away. "If we don't have this conversation, it's going to happen without us," he said.

"I'm getting ready to curl up on the floor into a ball and roll around."

Ed Tatum, American Municipal Power

Farber, who had registered the first concern with the proposal, nonetheless expressed support for it, saying the committee was "letting the perfect be the enemy of the good" and that he didn't want to see it succumb to "paralysis by analysis."

Stakeholders acknowledged that the current proposal was "substantially different" from past iterations. Tatum said he needed to confer with the coalition before deciding the next step.

Stakeholders not Quite Done with Seasonal Capacity

Stakeholders balked at PJM's suggestion to sunset the Seasonal Capacity Resources Senior Task Force, saying there is more work to be done despite the RTO's announcement Oct. 19 that its Board of Managers will file a "facilitated aggregation" proposal with FERC. (See *PJM to Seek FERC OK for Seasonal Capacity Proposal*.)

While stakeholders praised the job PJM's Scott Baker has done steering the task force, they derided the RTO's handling of the issue. PJM's proposal was one of five voted on by the task force in September, but it received only 32% support.

CPower's Bruce Campbell said he was "very disappointed in PJM's actions in … pre-empting a viable discussion." Guerry explained that the reason some stakeholders were upset is because the RTO's action was contrary to stakeholders' "expectation of the rules and how the process was supposed to play out."

Barker, however, commended PJM's leadership on the issue. "Let's sunset it and move on," he said.

Bruce suggested a "quick hibernation," as when it announced the planned filing, PJM had noted that there were additional pieces of the structure to work out.

The indignation with PJM transitioned to the next discussion, in which Whitehead presented to the committee his proposal from the task force. His "substantive but simple" proposal would allow base capacity to participate in the auction for another year to allow enough time to fully consider the topic, he said.

"It's our view that the board decision unfortunately wasn't informed by some of these critical pieces of the stakeholder process," he said.

Seasonal resource owners were only able to address the differences between forecasted peak loads in summer and winter "at kind of a cursory level," he said. PJM has experienced colder periods than the 2014 polar vortex on which much of the capacity decision-making is based, he said. Its top winter peak-load day occurred in February 2015.

"I'm not sure it continues to make sense to continue to make reliability procurement decisions based on one year's experience," he said. "It doesn't make a lot of sense that we would buy capacity to run somebody's air conditioner in January."

While Farber said the additional transition year was "critical," Howard Haas of Monitoring Analytics, PJM's Independent Market Monitor, objected to the proposed extension. Barker said the polar vortex highlighted issues that further investigation of a new

Continued on page 24

PJM NEWS

No End in Sight for PJM Capacity Market Changes

Continued from page 23

seasonal-capacity construct might not address. "We need to be mindful of the nature of the winter constraints that we saw," he said.

"I'm not disputing that this needs to be studied. That's actually what I'm asking," Whitehead said.

Later in the meeting, James Wilson of Wilson Energy Economics proposed a problem statement and issue charge to review PJM's procedures for evaluating winter-capacity needs. "I don't think it calls for a lot of changes, mainly just a few updates," Wilson said. "It was really never much of a topic. … Winter capacity matters, we've learned."

PJM's Stu Bresler indicated that the FERC filing will likely occur prior to November's MRC meeting. Because the task force sunset, the base capacity extension and the winter resource analysis proposals were presented as first reads, none will be voted on until that meeting — presumably after PJM has made its filing.

Underperformance Changes Would Weaken CP, Says PJM, Monitor

Asked to develop proposals for two CP issues, the Underperformance Risk Management Senior Task Force was only able to find consensus to endorse one.

The task force was charged with analyzing PJM's pseudo-ties and flowgates to determine the impacts of integrating external CP resources. Of the four options proposed, the highest approval that any package reached was 38%. However, 78% preferred a change over the status quo.

PJM's Rebecca Carroll said feedback is being collected from stakeholders through a new nonbinding poll, the results of which will be available this week. The group expects to review results and determine next steps at its Nov. 10 meeting.

The task force was also assigned to review underperformance rules. The endorsed package — which received nearly 55% approval — will be put up for a sector-weighted vote at the November MRC.

It would make several changes to Manual 18: PJM Capacity Market and Attachment DD of the Tariff including:

- Basing the nonperformance penalty on the highest Base Residual Auction clearing price in any locational deliverability area instead of net cost of new entry;
- Allowing underperforming units to find replacement megawatts from over-performing units in the same performance assessment hour area. Under current rules, such transfers are allowed only within the same capacity account with PJM;
- Adding a new mechanism for transferring the replacement megawatts; and
- Adjusting the stop-loss provision from annual to monthly.

Haas was quick to register his objection to the proposal. "We think it's going to weaken the product to the point where it no longer incents performance," he said.

Others agreed, including Barker, PJM Public Power Coalition's Johnson and the RTO itself.

"PJM cannot find itself in a position to

Continued on page 25

> **"We need to be mindful of the nature of the winter constraints that we saw."**
>
> **Jason Barker, Exelon**

FERC Reinstates Md. Solar Project to PJM Queue

No Harm, No Foul, Commission Says

By Rory D. Sweeney

FERC granted a Maryland solar developer's request to reinstate its position in PJM's interconnection queue, which the company lost because of delays in obtaining state approval (ER16-2645).

Dan's Mountain Solar initiated the interconnection review process in 2014 to connect its 18.36-MW project in Allegany County to Potomac Edison's 138-kV Frostburg-Ridgeley line.

The developer obtained its facilities study from PJM in December 2015, triggering a 60-day countdown for signing the interconnection service agreement (ISA). PJM later extended the ISA deadline to June 2, 2016.

But the developer didn't receive its Certificate of Public Convenience and Necessity from the Maryland Public Service Commission — a requirement for signing the ISA — until July 11, two-and-a-half months after the state had promised a decision and just more than a month after the project was automatically withdrawn from the PJM queue on June 7.

Because transmission upgrade costs are determined by a unit's interconnection position, PJM intervened to note that reinstating Dan's Mountain's queue position could disadvantage interconnection applications that have been filed in the interim. But in a Sept. 21 email to the developer, PJM acknowledged that as of that date, no other projects would be negatively impacted by its reinstatement.

FERC granted the developer's request for a waiver of the deadline following an expedited review, saying "it appears this waiver will not harm third parties."

"Although PJM's Oct. 6, 2016, comments assert that the potential for harm to third parties increases as time passes, PJM did not indicate that harm is imminent," the commission said in its Oct. 25 order.

The waiver allows Dan's Mountain to continue where it left off and avoid restarting the application process.

PJM NEWS

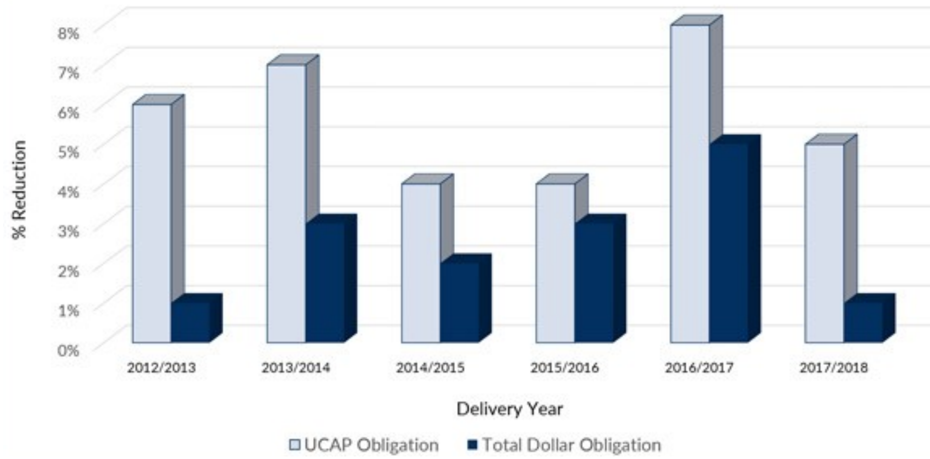
No End in Sight for PJM Capacity Market Changes

Continued from page 24

support this package" Bresler said, explaining that it's "too far down" the slope of not requiring CP units to perform at the exact time they're needed, which the existing construct was specifically designed to do.

The proposal did have some champions though, including Talen Energy's Tom Hyzinski and John Horstmann of Dayton Power and Light. Horstmann said adding a monthly stop-loss provides protections for the supplier and ultimately reliability because a monthly limit would provide generators with an incentive to perform throughout the delivery year. Additionally, basing penalties on net CONE creates inconsistent penalty rates across differing LDAs, he said, disproportionately penalizes the lowest-priced capacity with the highest percentage loss of revenue for a PAH penalty. Hyzinski said there are many other incentives to perform that keep the proposed changes from diluting CP.

Later in the meeting, Barry Trayers of CitiGroup Energy proposed another Manual 18 revision to eliminate a prohibition on how early a capacity obligation replacement can be made. Trayers' proposal was followed by a friendly amendment from PJM that refined the language of the proposed rule change. The proposal will be brought back at November's MRC for a vote. No one voiced any concerns about how the separate replacement changes would integrate.



Because prices in PJM's Base Residual Auction are much higher than those for Incremental Auctions in which the RTO sells excess capacity, load has recognized little savings for the reliability benefits it has forgone. | *PJM*

Buy High, Sell Low?

Stakeholders would consider anew the price differences between the BRA and incremental auctions under a problem statement proposed by Whitehead.

Whitehead said the stark differences between the BRA clearing prices and the lower IA prices raises the potential for abuse. Noting that load is receiving cents on the dollar on excess capacity released by PJM in the later auctions, he proposed investigating whether IA prices yield reasonable and accurate results and revise policies if they don't.

Citing results from recent auctions, Whitehead highlighted the disparity that creates an incentive to sell during the BRA and buy back during the IA at much lower prices.

Other stakeholders agreed. Calpine's David "Scarp" Scarpignato said the structural issues between the two auctions "[create] a lot of speculation."

For all but one delivery year between 2012/13 and 2016/17, the third IA auction clearing price has been a fraction — between 8 and 20% — of the BRA price.

The only time the IA price exceeded the BRA was 2015/16, when PJM did not sell back excess capacity in the IA.

Whitehead also noted that PJM's excess sales have resulted in much larger reductions in the capacity acquired than in the cost savings to load. "In essence, load gets a lot less reliability in exchange for a negligible reduction in capacity cost," the problem statement says. "Load should be appropriately compensated for the resulting reliability reduction, in consideration of the fact that, among other benefits, capacity in excess of the PJM's planning targets can have value in a tail reliability event."

The issue is not a new one. In 2013-14, stakeholders wrestled with ways to eliminate what some called "arbitrage opportunities" between the BRA and IAs. The effort ended in May 2014, after FERC rejected a plan to curb speculation in the auction, saying it created undue barriers to entry. (See *PJM Wins on DR, Loses on Arbitrage Fix in Late FERC Rulings*.)

The commission ordered a Section 206 proceeding and technical conference to explore the issue further (EL14-48) but did not schedule the conference after PJM asked the commission to defer action while it developed CP.

SPP News

SPP Gala Celebrates 75 Years of Service

Left to right: Asa Hutchinson, Susan and Nick Brown, Colette Honorable | *SPP*

LITTLE ROCK, Ark. — SPP celebrated its 75th anniversary this week with a gala featuring political and regulatory figures, an orchestral piece, a commemorative video and a coffee-table book.

The gala, held Monday night in downtown Little Rock, attracted more than 300 attendees, including Arkansas Gov. Asa Hutchinson and other state officials, FERC Commissioner Colette Honorable — former chair of the state Public Service Commission — board members, stakeholders and community leaders.

They were treated to the Arkansas Symphony Orchestra Brass Quintet's rendition of "Heralding Light," which was composed for the occasion.

SPP also marked the occasion by releasing a 20-minute video and a history book, both called "The Power of Relationships." The book spent a year in development, with former SPP executive Les Dillahunty providing much of the preliminary work, and features comments from previous and current members and officers.

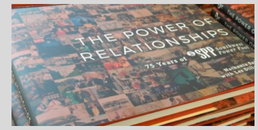
"SPP has long distinguished itself through our relationship-based approach to doing business," SPP CEO Nick Brown and Board Chair Jim Eckelberger wrote in the book's foreword. "SPP exists because of its shareholders. Period. Without their support — logistically, financially, politically and often even emotionally — we would not be where we are today, if we were anywhere at all."

SPP was created by 11 regional power companies just nine days after the Japanese attack on Pearl Harbor in 1941 to ensure reliable energy for an aluminum plant supporting the wartime effort. The RTO now serves 18 million people across 14 states.

— Tom Kleckner

Arkansas symphony orchestra brass quintet performs "Heralding Light" | *SPP*

Ten things you may not have known about SPP (from "The Power of Relationships"):



1. SPP's first computer had two memory cards "the size of a pizza box," each with less than a megabyte of memory. "My iPhone now has more power in it," says Malinda See, vice president of corporate services. One of SPP's 14 original employees, See said she would take the reel-to-reel backup tapes home for safekeeping.
2. SPP's operating budget, less than $53,000 in 1969, didn't exceed $1 million until 1990. It's currently $210 million.
3. Back when the fledgling organization had 14 employees, it nonetheless kept a strict accounting of the few fixed assets it had. "If they had to buy a chair," CFO Tom Dunn recalls, "they had utility members ask, 'Why do you need more chairs? What happened to the old chair?'"
4. SPP's original 11 members were future Entergy operating companies Arkansas Power and Light, Louisiana Power and Light and Mississippi Power and Light; future American Electric Power subsidiaries Public Service Company of Oklahoma (PSO) and Southwestern Gas and Electric (now Southwestern Electric Power Co.); Southwestern Light and Power (later acquired by PSO); Empire District Electric; Kansas Gas and Electric (now Westar Energy); Nebraska Power (Nebraska Public Power District); Oklahoma Gas & Electric; and Texas Power and Light (Luminant, Oncor and TXU Energy).
5. Dillahunty and Jay Caspary, now director of research, development and Tariff studies, were recognized by the Kansas House of Representatives as honorary citizens in 2006 for the amount of time they had spent in the Sunflower State working on transmission-expansion development.
6. Board Chair Jim Eckelberger, a retired U.S. Navy rear admiral, and Director Harry Skilton have been with SPP since before it gained RTO status in 2003. They were both part of an independent board seated in 2000 as a precursor to RTO status.
7. It took three attempts and three years before SPP was approved by FERC as an RTO. In the interim, SPP also tried to merge twice with MISO, calling the effort off for good in March 2003.
8. Former CEO John Marschewski once accidentally locked himself out of SPP's offices in the days before identification badges. Marschewski waited for another tenant to let him in the building, then removed drop ceiling tiles and climbed over the wall to get into his office from the hallway.
9. CFO Tom Dunn dressed as Superman for a company-wide function several years ago. Unfortunately, his superpowers failed him when he tried to fly off the stage. He broke one foot and bruised the other upon landing.
10. The largest outage in SPP's history came in July 1993 when sagging power lines tripped after coming into contact with trees and resulted in the loss or reduction of more than 300 MW of load. The interruption was centered on the four-state border area of Arkansas, Kansas, Missouri and Oklahoma.

SPP News

Board of Directors/Members Committee Briefs

RUC, Shortage Pricing Practices Challenged

LITTLE ROCK, Ark. — Mike Wise, Golden Spread Electric Cooperative's senior vice president of commercial operations and transmission, once again argued against a revision request funneled through the SPP Market Working Group that replaces the terms "head-room" and "floor-room" with "instantaneous load capacity."

Wise told the Board of Directors and Members Committee that with MRR173, part of a compliance package responding to FERC Order 825, procuring rampable capacity through the reliability unit commitment (RUC) process "masks shortage conditions in a manner inconsistent with the requirements of FERC's shortage-pricing rule."

"We're RUCing them left, we're RUCing them right, we're RUCing them all the time. [That] dampens prices and dampens the market," Wise said. "It's just an advanced form of an [energy imbalance service] because of all the RUCing that's going on.

"There are so many new resources … that are rapidly coming on that make appropriate price signals even more important. Our main goal should be to allow resources to clear based on market offers, not cost, in the dispatch model itself. The process needs to be improved substantially."

Not so fast, said American Electric Power's Richard Ross, the MWG's chair. He said the claim that SPP is "RUCing things as they see fit couldn't be further from the truth."

"We could change the rules and say we don't even need the reserves, but we'd have more scarcity events," Ross said. "Being a balancing authority comes with obligations. It is unacceptable to go into real-time operations; not only unacceptable, but it's not compliant to go in short. This revision is clarifying exactly what staff should be doing."

Ross said MRR173 and MRR175, which seeks to comply with Order 825 by using shortage pricing for any interval in which energy or operating reserves are short, would address Wise's concerns. Both revisions are necessary for SPP to make a planned FERC compliance filing in January.

A third revision, MRR188, gives staff the option to include as much as 100% of instantaneous load capacity (as opposed to the current 0% of capacity) in clearing the day-ahead market. The revision is a protocol change, so it did not need board approval.

The three revisions "are all tied together," Ross said. "What's happening with this change, and the change in 188, is to move that procurement into the day-ahead market. It's an improvement. We don't want scarcity events. We want right pricing."

"I don't believe there are any cost implications at all. I believe it's a practice we have to live with at SPP," said COO Carl Monroe, pointing to the Price Formation Task Force as another group addressing the ramping issue. The task force is expected to wind down its work by year-end and then hand it over to the MWG.

© RTO Insider

"The entire MWG is sympathetic to you," Ross said to Wise. "I absolutely feel you should recover all costs for generating energy out of those [quick-start] resources. The answer is to set prices at the cap, frequently, in order to allow that to happen. We think shortages happen and are being priced appropriately, but this is a first step. We need to … be in position to comply with the FERC order and after that, we can improve on it."

Wise said he was encouraged by Ross' comments.

"To the extent we can eliminate RUCs, I really want us to get there," Wise said. "It's not an issue that's going away. We should be procuring through the market and the bid-stacking process."

Still, Wise wound up casting the lone opposing vote against MRR173. He was joined in opposing MRR175 by Dogwood Energy's Rob Janssen, who said he objected to staff inserting language the week before October's Markets and Operations Policy Committee meeting calling for a $5,000 spike in the operating reserve demand curve (ORDC) during a scarcity event.

"I look at pricing to have the right price at the right time for the right reason," Janssen said, paraphrasing an SPP motto. "Going straight to $5,000 in an event like this is unnecessary. The single highest price we've seen at our node is $2,000. It's an excessive change, in my opinion. If we can have further discussion about reducing the number, I'd appreciate that."

Richard Dillon, SPP's director of market design, responded that the ORDC will go straight to $5,000 "because it's a demand curve, and we have run out of ramp at that point."

"We set it at $5,000 so we don't choose to do other things and cause reliability issues," he said. "If we're short all the reserves in the [load zones] and the region, the prices have the potential to be at $3,400, so we needed this one to be higher than that value."

The MWG "will make the language as appropriately flexible as we can," Ross said. "We have some implementation time before the compliance filing is put into effect."

The board also approved two other revision requests brought forth by the MWG:

- RR183, which updates the violation-

Continued on page 28

SPP NEWS

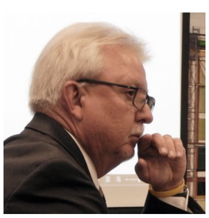
SPP Board Lets Action on Z2 Stand; Litigation Likely

By Tom Kleckner

LITTLE ROCK, Ark. — The SPP Board of Directors and Members Committee decided last week to take no further action on the contentious Z2 crediting issue, leaving unhappy stakeholders likely to seek redress from FERC or the courts.

The board discussed the Markets and Operations Policy Committee's recommendation to "follow the Tariff" and reject requests that $114.1 million in directly assigned Z2 network upgrades be allocated to SPP's base plan. However, it took no votes on the matter Oct. 25, which let stand the MOPC's decision, which was supported by 83% of members voting. (See *MOPC Rejects Z2 Waivers; Task Force Seeks Changes*.)

The board in July formed a task force to review requests from members who SPP staff had said didn't qualify for waivers from $36.9 million in directly assigned upgrade costs, while also addressing "equity concerns." The group also reviewed another $77.2 million in direct costs from members who didn't request waivers.



Evans

Les Evans, COO of Kansas Electric Power Cooperative (KEPCo), one of the companies requesting a waiver, once again expressed his dissatisfaction with the process after being "wrongly assigned" $6.2 million because its resource-to-load ratio exceeded a 125% threshold.

"The 83% that voted to follow the Tariff does indicate that 17% of us feel disenfranchised and that things are not equitable," Evans said.

Evans argued KEPCo was granted four transmission service requests from a 2012 aggregate study, and that there were no directly assigned costs in the agreements.

Pointing to the directly assigned costs he said KEPCo was assessed four years later, Evans said SPP's treatment of his company fails the RTO's "but-for" test, which requires transmission customers to fund transmission improvements that would not be required but for their additional load. The test is triggered by a 3% increase on a line's directional flow in the same direction as the power flow that caused the upgrade.

"Under the process we're using right now, a sponsored upgrade can be put back into a model from years ago, and if I have a 3% flow on that facility, I would be responsible for directly assigned upgrade costs under that possibility. I would say that is not fair, it's not equitable and I don't think there's anybody that can stand here with a straight face and say that passes a 'but-for' test."

Evans worked with staff to draft language for two different motions addressing his arguments. One required transmission reservations assigned a payment obligation for an upgrade be included in the original aggregate study model. The other would mandate that service agreements explicitly include directly assigned upgrade costs in order to be directly assigned to a transmission customer.

Evans failed to get a second on either motion, the only two offered up by the board and committee.

"We have an opportunity here, as a group, to solve the problem," Evans said. "If the problem's not solved [today], from my perspective and KEPCo's perspective, we'll seek other solutions. SPP loses control of how the problem is resolved. This is the place to do it."

Staff pointed out either motion would cause about a six-week delay to calculate the historic Z2 credits and obligations, which date back to 2008. Invoices settling charges and credits under Attachment Z2 for the March 2008-August 2016 period are to be issued this week.

"Following the Tariff should be clear, but how clear can 5,275 pages be?" Director Phyllis Bernard asked. "Perhaps it's time for … alternative dispute-resolution with a possible third party, or to go to FERC."

"We've been waiting eight years to get this done. Let's get it done," said The Wind Coalition's Steve Gaw, noting SPP's transmission-dispute resolution process could still provide an avenue for members to plead their case. "I would encourage us to move forward."

"I'd love for consensus to be unanimous, but that's not what we have," SPP CEO Nick Brown said. Reversing the MOPC's endorsement would mean "we'll be supporting 17% at the expense of 83%."

"Bottom line, this will go to FERC," Brown said. "I have no doubt what KEPCo's response to this will be."

Evans' response was terse. "KEPCo is evaluating all possible venues for a remedy to its issues," he told *RTO Insider* on Friday.

Staff told members Thursday it is billing almost $110 million in regionwide, aggregate net payable historic amounts. It said $94.8 million will be invoiced as a lump sum, and the remaining $15.1 million will be billed in 20 installments through August 2021 to those members who chose the payment plan approved in April.

Board of Directors/Members Committee Briefs

Continued from page 27

relaxation limits' operating constraint to allow additional redispatch to solve cases with fewer violations, passed with two opposing votes.

- RR193, which adds rules for solar resources to the market protocols and Tariff, including incorporating a solar forecast in SPP studies, increasing the solar forecast's accuracy and including solar resources in dispatchable variable energy resource registration. The revision received two abstentions.

Brown Says Cybersecurity Biggest Challenge

SPP CEO Nick Brown said during his president's report that cybersecurity issues will be SPP's — and the industry's — biggest challenge in 2017.

"Our ability to rely on the Internet of things is being challenged," he said. "That makes us

Continued on page 29

SPP NEWS

Board of Directors/Members Committee Briefs

Left to right: Golden Spread's Mike Wise, Northeast Texas Electric Cooperative's Jason Atwood, SPP Director Josh Martin and Dogwood Energy's Rob Janssen | © *RTO Insider*

Continued from page 28

rethink how we operate our businesses and how we rely on the Internet going forward."

Brown said SPP's organizational groups will all spend time at their next meetings gathering feedback "to decide the appropriate level of cybersecurity for this organization."

"Our systems are there to serve you," he said, "but the cost to comply … goes up."

Brown also talked about several other initiatives. He reminded members and the board that he had labeled 2016 as "The Year of the Audit" back in January. He said SPP completed SERC Reliability compliance and FERC financial audits without findings, and he hopes a Critical Infrastructure Protection Version 3 audit begun in 2013 will be completed soon.

An internal initiative to reward employees for finding disparities between SPP's 5,275-page Tariff and actual operating practices resulted in 10 self-reports to FERC, Brown said. He said the commission took no action on the reports.

FERC's recommendations to "improve the appearance of independence" of the Market Monitoring Unit have been "implemented or are in the process of being implemented," he said. The commission issued an audit report of the MMU in July, saying SPP executives had "inappropriate" involvement in the MMU's oversight and called on the RTO to "strengthen its independence." (See *FERC Calls for Changes to Protect SPP Market Monitoring Unit Independence*.)

The Integrated System's first year of SPP membership resulted in $67 million in net savings to the RTO's footprint, including $27 million to original members "that otherwise would not have been there."

Finally, Brown said revenues are down 3.9% because of low loads. SPP budgeted the 2016 administrative fee using 2015 coincident peak loads, which were projected at 407 million MWh. The peak load forecast is now 394 million MWh.

Directors, Trustees, Members Re-elected

Members and directors re-elected several incumbents to the board, Regional Entity trustees and Members Committee during SPP's Annual Meeting of Members.

Stuart Solomon (AEP) and Kelly Harrison (Westar Energy) were re-elected to represent the investor-owned sector; Stuart Lowry (Sunflower Electric Power) and Mike Risan (Basin Electric Power Cooperative), cooperative sector; Jeff Knottek (City Utilities of Springfield), municipal sector; Janssen, independent power producer/marketer sector; and Brett Leopold (ITC Great Plains), independent transmission companies.

Directors Julian Brix and Phyllis Bernard were re-elected to new three-year terms on the board. Bernard was first elected to the board in 2003 and Brix in 2008.

Stephen Whitley was elected to an additional three-year term as an RE trustee. Whitley completed former trustee John Meyer's unexpired term following the latter's resignation in March over a conflict with the bylaws of Western Interconnection reliability coordinator Peak Reliability, where Meyer is vice chair.

Ross Forgoes Razor for Charity

Ross, an often outspoken presence at SPP and ERCOT stakeholder meetings, has made himself even more noticeable with the recent addition of facial hair.

Ross

Ross began growing his beard following SPP's board and MOPC meetings in July. There, he issued a challenge to his fellow stakeholders: If they contribute more than $1,000 to the United Way organizations of Tulsa, Okla., and Little Rock, he would not shave until Thanksgiving.

"And if you contribute more than $2,000, I will go full Duck Commander," Ross said, referring to the popular "Duck Dynasty" television program.

Ross was unable to meet the higher goal, but his neatly groomed beard attests to what he was able to raise.

Consent Agenda Adds Working Group, Approves IEP Panel

The unanimously approved consent agenda included chartering the Supply Adequacy Working Group, which will take on tasks from the Generation Working Group and Capacity Margin Task Force; adding the Nebraska Public Power District's Traci Bender to the Strategic Planning Committee; expanding the Oversight Committee to five independent directors; and accepting the Oversight Committee's 11 candidates for the Industry Expert Pool that will evaluate and recommend competitive-upgrade projects.

The board and members also accepted the SPC's recommendations to improve the competitive transmission process, the Project Cost Working Group's recommendation to reset the baseline for an AEP 345-kV project in southeastern Oklahoma and staff's recommendations to accelerate one project and withdraw the notice-to-construct for another. (See *SPP Panel OKs Changes to Competitive Transmission Process*, "AEP Project's 41% Overrun Approved" and "Members Vote to Cancel 69-kV line in West Texas," *SPP Markets and Operations Policy Committee Briefs*.)

Other rule changes approved by MOPC were:

- MWG-MRR178: Specifies that SPP's Market Monitoring Unit will review the costs included in each mitigated resource offer, on an *ex post* basis.

Continued on page 30

SPP NEWS

SPP RSC Approves New Member Cost Allocation Process

By Tom Kleckner

SPP's Regional State Committee last week approved a process for reviewing new members' effect on regional cost allocation, but not before rejecting language that stakeholders have been unable to agree on since July.

The RSC approved the Cost Allocation Working Group's New Member Cost Allocation Review Process after deleting an introductory paragraph that dealt with the effective date for highway/byway cost sharing. The committee asked the working group to revise the paragraph and bring it back in October after SPP staff raised objections in July.

John Krajewski, a consultant with the Nebraska Power Review Board, said the CAWG never reached consensus on whether to include the paragraph in the document but felt the language was "reasonable" if the RSC decided to keep it. The revised paragraph specified that "the effective date of cost sharing is an area over which the RSC has primary responsibility."

At issue was whether the language "tied the hands" of the RSC.

The RSC tied 5-5 on following the CAWG's recommendation to include the language. The committee then unanimously approved the document without the introductory paragraph.


Lyons (left) and Midwest Energy's Bill Dowling | © *RTO Insider*

The document creates a roadmap for the RSC and CAWG to follow when a potential new member asks for significant changes to the Tariff or membership agreement that would affect the committee's regional cost allocation.

The process became necessary after the Integrated System joined SPP last October, when much of the negotiation over the integration took place between the new members and staff. The parties agreed to propose to current members and the RSC a method to include the new system under SPP's highway/byway funding methodology, while also providing the Western Area Power Administration's Upper Great Plains Region a federal service exemption from regional funding.

Committee Elects 2017 Officers

The meeting was New Mexico Public Regulation Commission Chairman Patrick Lyons' last as RSC chair; he will relinquish the gavel at the end of the year.

"It's been a learning experience," Lyons said. "I've learned people really do care what the ratepayers have to pay."

The committee unanimously approved Missouri Public Service Commissioner Stephen Stoll as its chair for 2017, Kansas Corporation Commissioner Shari Albrecht as vice chair and South Dakota Public Utilities Commissioner Kristie Fiegen as secretary and treasurer.

Members also approved a 2017 budget of $321,700, an $8,400 increase over this year's because of higher travel expenses.

Board of Directors/Members Committee Briefs

Continued from page 29

- MWG-MRR179: Aligns the protocols with FERC-approved language (ER15-2265) to ensure long-term congestion rights are not affected by potential resource hub terminations, and that resource hubs used in bilateral contracts can't be unilaterally terminated by the hub's owner.
- MWG-MRR181: Corrects outdated references in the Tariff and protocols related to the allocation of annual auction revenue rights, an oversight noted by FERC (ER16-13).
- MWG-MRR185: Clarifies which document — SPP Planning Criteria or SPP Operating Criteria — is referenced when used in the market protocols and Tariff.
- ORWG-RR168: Requires transmission owners to provide the highest available emergency ratings and specifies SPP's interpretation of those ratings.
- TRR88: Modifies the time of day when unscheduled firm transmission is released for sale as hourly, non-firm transmission service for those members wishing to coordinate next-day scheduling with the Western Electricity Coordinating Council.
- RTWG-RR164: Updates Tariff Attachment O to correctly reflect the current near-term planning process schedule, which is now conducted in the April-March timeframe.
- RTWG-RR174: Revises Attachment AQ of the Tariff to eliminate a requirement that transmission customers submit a request for changes in delivery point facilities when there is no corresponding change in load.
- RTWG-RR176: Corrects and clarifies responsibilities and requirements under the process that allows generation resources to be compensated for reactive support.
- TRR88: Modifies the time of day when unscheduled firm transmission is released for sale as hourly, non-firm transmission service for those members wishing to coordinate next-day scheduling with WECC.

— Tom Kleckner

Entergy Earnings Surpass Expectations; Wall Street Unimpressed

By Tom Kleckner

Entergy reported third-quarter earnings of $2.16/share last Tuesday, beating analyst expectations, but its stock continued a months-long decline.

Despite beating Wall Street predictions of $1.95/share, according to Zacks Investment Research, Entergy shares have lost about $2.48/share since last Monday's close, a 3.3% drop. Its fall below $72/share continued its slide since setting a 52-week high of $82.08 in early July.

Nine of 11 analysts tracked by Zacks rate Entergy stock as a hold, with one rating it a strong buy and another a strong sell.

After the earnings report, Morgan Stanley downgraded Entergy to underweight, citing weak sales and risks to earnings from the potential disallowance of nuclear costs. It set a $68 price target.

Entergy has announced it plans to shutter its Vermont Yankee (already being decommissioned) and Pilgrim (in 2019) nuclear plants in New England, and the company is attempting to sell its James A. FitzPatrick unit in New York in Exelon. Costs related to the closures were reflected in the corporation's 2015 earnings, Entergy CEO Leo Denault said during a conference call with industry analysts Tuesday.

Denault said the company's Arkansas and New Orleans operating companies have made filings with state regulators seeking approval to deploy advanced metering infrastructure (AMI) as early as 2019. Denault said AMI "will lay the foundation for an integrated energy network."

Theo Bunting, Entergy's group president of utility operations, told analysts the corporation has projected its total AMI investment at $900 million "on a system basis," and includes development of the technology's backbone.

"As you go through the filings, you will see that there were some costs we're asking to defer that will get fully incurred prior to the full functionality of the meters themselves," Bunting said. "We also believe that infrastructure is useful for other systems as well. So I think our perspective is the cost is consistent with what we've seen in implementations across the country."

"We continue to make those modernizing investments that will lower production cost [and] provide significant benefits to our customers," said Denault, adding that the corporation's financial outlook reflects "our prudent decision to position the nuclear fleet for sustained operational excellence."

Denault also told analysts the company has 48 projects "totaling roughly" $480 million up for consideration in MISO's 2016 Transmission Expansion Plan (MTEP). Entergy has submitted another $700 million of proposed projects for MTEP 2017.

"We will work with MISO on the selection process for those proposals over the course of the next year," Denault said.

The company says it expects earnings of $6.60 to 7.40/share for the year.

Earnings Up, Xcel Touts 'Steel-for-Fuel' Strategy

By Tom Kleckner

Xcel Energy reported an increase in earnings for the third quarter as the company said its "steel-for-fuel" strategy of replacing fossil fuel plants with wind turbines will provide a solid blueprint for future growth.

The company reported third-quarter earnings of $458 million ($0.90/share), up 7.5% from the $426 million ($0.84/share) a year earlier. The results bested analysts' expectations of 87 cents, according to Zacks Investment Research.

"The whole premise of steel-for-fuel is you can do things on an economic basis cheaper than the fossil alternatives," CEO Ben Fowke told analysts during a conference call Thursday. "In reality, the environmental benefits will be icing on the cake. So, when you're not impacting customer builds and you're driving environmental leadership, it's really a unique position for us to be in."

Xcel proudly points to its designation by the American Wind Energy Association as the nation's No. 1 utility wind-energy provider for 12 years running. Wind energy accounted for 17% of the energy Xcel generated in 2015, and it projects that figure to grow to 24% by 2020.

Much of that has been produced by long-term contracts with third parties, but the Minneapolis-based company announced earlier this week it would build four new wind farms in Minnesota and North Dakota with a total capacity of 750 MW.

In September, Colorado regulators approved Xcel's plans to begin construction on its $1.1 billion, 600-MW Rush Creek Wind Project, allowing Xcel to claim $443 million in federal tax credits. The Rush Creek project is expected to come online in 2018.

"We expect [these] wind projects will generate hundreds of millions of dollars in fuel savings for our customers, which will more than offset the capital cost [to build them]," Fowke said.

CFO Bob Frenzel told analysts the company has updated its five-year capital forecast and now expects to invest $18.4 billion through 2021, including $3.5 billion on renewables. That includes the Rush Creek project and the Minnesota-North Dakota wind farms.

"When you look at the economic price point … that we are seeing with wind, I think we have opportunities potentially in Texas and New Mexico too, just on the economic merits alone," Frenzel said.

Analyst Angie Storozynski of Macquarie Capital questioned whether adding renewables to the rate base in a time of no load growth is the "low-risk" growth strategy the company claims.

Vice President of Investor Relations Paul Johnson acknowledged that the company will be adding capacity that might not be needed until it retires coal plants. "We're just taking opportunity to capture the full" production tax credit, he said.

"This is our resource plan. … We can build wind competitively, and I think we've earned the right to own wind in our backyard," Fowke added. "It does require alignment with your regulators, but I think we have it."

Xcel narrowed its 2016 earnings guidance to $2.17 to $2.22/share, down from the previous estimate of $2.12 to $2.27/share. "Our year-to-date weather-adjusted electric sales remain relatively flat," Frenzel said, explaining the company's caution.

The company's stock price opened at $40.33/share before Thursday's earnings announcement. It closed Friday at $40.68.

Earnings call transcript courtesy of Seeking Alpha.

Company Briefs

Duke Energy to Provide Remote Services to Block Island Wind Farm

Duke Energy Renewables has signed a five-year deal to provide remote monitoring, control and dispatch services to Block Island Wind Farm — the nation's first offshore wind facility.

The 30-MW wind farm, located off the coast of Rhode Island, is expected to begin producing electricity in November.

Duke Energy presently provides control and monitoring services to non-Duke projects totaling about 2,000 MW.

More: Charlotte Business Journal

PG&E Applies for Rate Increase Spurred by Diablo Canyon Closing

Pacific Gas & Electric is applying to the California Public Utilities Commission for a 1.6% rate increase after promising earlier this year that closing its Diablo Canyon nuclear facility would not raise customers' rates.

The proposed increase amounts to $1.766 billion to be collected over an eight-year period.

PG&E spokesman Blair Jones said last week that the "short-term rate increase will be offset in the long term."

More: The San Diego Union-Tribune

Sunrun Partners with LG Chem to Offer Solar Panels with Batteries

Sunrun will offer solar arrays paired with in-home batteries thanks to a partnership announced last week with LG Chem, which supplies batteries to 16 of the world's largest automakers.

The Korea-based battery builder will supply lithium-ion batteries for Sunrun's BrightBox system, which allows homeowners to store solar energy generated during the day for use in the evening.

Sunrun began offering BrightBox this year in Hawaii, using batteries made by Tesla Motors. It wants to expand the system into California beginning in 2017.

More: San Francisco Chronicle

DONG Energy Reaches 1,000 Offshore Wind Turbine Milestone

DONG Energy announced last week that it is the first company to install more than 1,000 offshore wind turbines.

Between 2016 and 2020, DONG plans to install more offshore wind capacity than it built in its preceding 25 years of business.

More: Clean Technica

Sims to Serve on Pinnacle West, Arizona Public Service Boards

Paula Sims has been elected to Pinnacle West Capital's board of directors and also will serve on the board of directors of Arizona Public Service, Pinnacle West's principal subsidiary.

The appointment is effective immediately and increases the number of Pinnacle West directors from 10 to 11 members, 10 of whom are independent.

Sims is a former senior executive at Progress Energy.

More: Pinnacle West Capital

Dominion Virginia Power Sees Peak Demands for Electricity

Dominion Virginia Power is seeing peak demands for electricity, with its customers having used 28.2 million MWh from July 1 to Sept. 30 — breaking an 11-year record.

"We are now seeing peak demands for electricity in both the summer and winter," said Robert M. Blue, president of Richmond-based Dominion.

The company has proposed building a transmission line over the James River from its Surry Nuclear Power Station to address increased demands.

More: Richmond Times-Dispatch

EnergySource Testing Process to Extract Lithium from Brine

EnergySource is testing a new five-step process to extract lithium from underground brine at its Featherstone geothermal plant by the Saltine Sea in California.

The company purchased several existing extraction techniques and is using its knowledge of the Saltine Sea brine to tweak those technologies, CEO Eric Spomer said.

A Texas investment firm just purchased a 38.5% interest in EnergySource and is funding more thorough testing of the extraction project, which Spomer expects will take about six months.

More: The Desert Sun

Xcel Energy Planning Four Wind Farms for Minnesota, North Dakota

Xcel Energy announced last week that it plans to build four new wind farms in Minnesota and North Dakota — a move that will increase its wind generation capacity by 60% in the Upper Midwest.

The four wind farms, which still require regulatory approval, will generate 750 MW.

The projects are part of a plan that Xcel announced in September to invest $2 billion to add 1,500 MW of new wind generation — or eight to 10 wind farms — by 2020.

More: Star Tribune

Shareholders File Suit to Stop Spectra's Merger with Enbridge

Shareholders have filed five separate lawsuits against Spectra Energy to stop its $28 billion deal to sell itself to Enbridge.

The suits, which were filed in the U.S. District Court in Houston, all allege that Spectra should have sought other merger partners who might pay more for the company.

Under the deal, Spectra stockholders would trade each of their shares for a 0.984 share of the combined company, which will keep the Enbridge name.

More: Fuel Fix

Idaho Power Project Lowers Temperature of Snake River

Idaho Power is lowering the temperature in areas of the Snake River in order to comply with regulations.

In July, the utility began work to narrow and deepen a channel by widening two islands just downstream of Walters Ferry. It will replace noxious weeds on the two islands with native trees that will help cool the water.

The project is the first of many planned for areas along the Snake River and is expected to end this month.

More: KTVB

Continued on page 33

COMPANY BRIEFS

Continued from page 32

Idaho Power Requests Early Exit from Nevada Coal Plant

Idaho Power filed a request with state regulators on Oct. 21 to accelerate its exit to 2025 from the coal-powered North Valmy Generating Station near Battle Mountain, Nev.

The utility, which owns 50% of the power plant, previously said it wanted to wean itself off of Unit No. 1 by 2031 and Unit No. 2 by 2035.

The accelerated exit would result in a $28.5 million cost increase, which would include decommissioning costs and capital investments forecast for the remaining life of the plant, Idaho Power said in its filing with the Public Utilities Commission.

More: *Boise Weekly*

New Reliant Plan: No Panels Needed to Purchase Solar in Texas

Reliant Energy is offering Texas customers the opportunity to purchase solar energy for 12 months at a fixed rate without installing solar panels. Reliant's 100% Solar 12 plan allows the company to procure the rights to solar energy through renewable energy credits.

More: *Fuel Fix*

FEDERAL BRIEFS

Obama Administration Sends $28M to Coal-Producing States

The Obama administration provided a $28 million infusion of federal grants last week to 13 coal-producing states to assist workers affected by job losses in the declining coal industry.

The money is part of the POWER Initiative, which provides federal funding for locally created programs that support new economic activities in coal regions as the nation moves toward cleaner energy. More than $66 million has been awarded to 71 projects this year.

More: *Reuters*

$3.6B Loan Program Will Fund Rural Electrification Projects


Vilsack

The Agriculture Department has announced a $3.6 billion loan program to fund rural electrification projects nationwide.

The program will benefit 82 projects in 31 states, Agriculture Secretary Tom Vilsack said, and it will add or upgrade 12,500 miles of rural electric transmission and distribution lines.

More: *The Kansas City Star*

OSHA Investigates Hydrogen Sulfide Exposure at Big Ox Plant

The Occupational Safety and Health Administration began an inspection Oct. 19 of Big Ox Energy's biomass plant in South Sioux City, Neb., after an employee of a contractor was hospitalized for hydrogen sulfide exposure.

The investigation is expected to take 60 to 100 days, said Darwin Craig, assistant area director at OSHA's Omaha office.

When the incident was reported, several homeowners who share a sewer system with the plant were reacting to foul odors that have since been traced to sulfides originating from the facility.

More: *Sioux City Journal*

Appellate Judges Grill Blankenship Defense

Two judges on the 4th U.S. Circuit Court of Appeals last week grilled the attorney for the former Massey Energy CEO Don Blankenship, who is seeking to have his criminal conviction overturned in connection with the deaths of 29 workers.

Blankenship was convicted of conspiring to violate mine safety and health standards after an April 2010 explosion at Massey's Upper Big Branch Mine, in Raleigh County, W.Va.

Judge James Wynn Jr. and Senior Judge Andre Davis raised issues about Blankenship's central arguments on appeal. Wynn repeatedly stated that he didn't think he agreed that the trial court wrongly instructed jurors on what constitutes a "willful" violation of federal mine safety and health laws.

More: *Charleston Gazette-Mail*

IEA Raises Forecast for 2021 Renewable Energy Production

In 2021, renewable energy sources will provide 28% of the world's electricity production, compared with 23% in 2015, the International Energy Agency forecasted last week.

The estimate is 13% higher than what the IEA forecasted last year.

The IEA attributed the change to increased government support in the U.S., China, India and Mexico and expected cost reductions of about 25% for solar panels and 15% for onshore wind.

More: *Agence France-Presse*; *The San Diego Union-Tribune*

Senators Push for Wave Test Center in Oregon

Six U.S. senators from the Pacific Northwest asked the Energy Department last week to choose the Oregon coast as the site for the nation's first grid-connected wave energy device test center.

Northwest National Marine Renewable Energy Center proposed the facility, which would consist of four berths for testing wave energy converters in big-wave conditions. It would include a subsea cable to carry up to 20 MW of power ashore.

Other than a potential project proposed for California, it is unknown whether other sites are vying for federal funding, which could cover up to 80% of the facility's cost.

More: *Portland Business Journal*

STATE BRIEFS

ARIZONA

APS, SolarCity to Air TV Ads to Support Favored ACC Candidates

The fight between the parent company of Arizona Public Service and rooftop solar company SolarCity to elect their favored political candidates to the state Corporation Commission continues, as both are spending big to air advertising on television.

Pinnacle West Capital, which owns APS, is planning to spend $1 million through a newly formed political committee to get three Republicans elected to the five-member commission. SolarCity has spent about $1.4 million supporting one Republican and two Democrats, according to financial disclosures.

It is widely believed that APS spent $3.2 million in 2014 to help elect the present all-Republican commission — an allegation that APS has neither confirmed nor denied. The FBI confirmed in June that it is investigating APS and a former regulator for issues involving the 2014 elections.

More: *The Arizona Republic*

CONNECTICUT

State Ends Effort to Increase Gas Capacity Following Court Decisions

State officials announced last week that they are abandoning their effort to increase natural gas capacity through an upgrade to existing transmission pipelines owned by Spectra Energy.

The decision came after courts in Massachusetts and New Hampshire ruled that the cost of upgrading pipelines could not be passed along to ratepayers in those states.

"If you can't spread the cost across the entire region, it doesn't make any sense to continue on," said Dennis Schain, a spokesman for the state's Department of Energy and Environmental Protection.

More: *New Haven Register*

ILLINOIS

Proposed Bill Asks Ratepayers for Up to $265M to Save Nuclear Plants

Exelon may be shuttering two of the state's six nuclear plants beginning in 2017 unless ratepayers statewide pay up to $265 million per year to save them.

Representatives of the power giant and its subsidiary, Commonwealth Edison, are seeking to pass a bill in the Legislature's November fall veto session that would save the Clinton plant from closure in 2017 and the Quad Cities plant from closure in 2018.

A draft version of the bill — which proposes the state's most far-reaching energy policy changes since deregulation in 1997 — also would tap ratepayers to fund new wind farms, solar installations, programs to cut power consumption and other items.

More: *Crain's Chicago Business*

MICHIGAN

Senate Could Vote in Two Weeks On Compromise Energy Bill

State senators could vote in two weeks on a compromise bill requiring state utilities to generate at least 15% of their electricity from renewable energy sources through 2012 — a 5% increase over what the law presently requires.

Additionally, the bill sets a goal that utilities achieve 35% of their power from a combination of renewable sources and energy efficiency savings by 2030. It also allows alternative energy suppliers to offer competing plans when utilities propose to build new power plants.

The bill ends a logjam between Republicans, who favor letting the market dictate utilities' choices, and Democrats and environmental groups, who believe utilities will not pursue sources such as wind or solar without a statutory requirement.

More: *Crain's Detroit Business*

MISSISSIPPI

NEP Solar Plant Lawsuit Against Aberdeen Postponed

A lawsuit over a solar plant that was to be built in Aberdeen has been postponed for 30 days to allow plaintiff National Energy Partners to retain new attorneys.

In December 2012, NEP signed a contract with Aberdeen to build a solar power system and sell electricity to the city over a 25-year period. In September 2014, NEP was assigned the rights for the project. Then-Mayor Cecil Belle subsequently canceled the contract when little progress was made over the next 12 months.

NEP argues that the contract required Aberdeen to make any complaints in writing and allow it time to correct any problems. The city argues that the contract — although signed by Belle — is invalid because the city board did not formally approve it.

More: *Mississippi Business Journal*

NORTH DAKOTA

Montana-Dakota Utilities Requests 6.6% Rate Increase

Montana-Dakota Utilities has filed a request with state regulators for a rate increase of $13.4 million per year, which amounts to 6.6%.

MDU also asked the state Public Service Commission to implement within 60 days of its filing an interim rate increase, which would be subject to refund if the final authorized increase is less than the interim.

The utility cited increased investments in facilities, depreciation, operation and maintenance expenses and taxes as the reasons for the proposed increase.

More: *Bowman County Pioneer*

OHIO

Report: Clean Energy Policies Good for Job Growth, Consumers

Two national environmental groups issued a report last week forecasting that the state would gain tens of thousands of jobs and consumers would reap millions in savings if the state increases its support for clean energy policies.

The report, issued by the Nature Conservancy and the Environmental Defense Fund, came at a time when some Republican lawmakers are seeking to extend a two-year freeze on the state's clean energy standards, which are scheduled to be lifted at the end of this year.

The report forecasts that by 2030 state support for clean energy policies would create an increase in jobs ranging from 82,300 to 136,000 and a reduction in consumers' electricity bills ranging from $28.8 million to $50.9 million per year.

More: *The Columbus Dispatch*

Continued on page 35

STATE BRIEFS

Continued from page 34

RHODE ISLAND

Utilidata, National Grid Strike Deal to Expand EE Technology

Technology company Utilidata has announced an agreement with National Grid for a statewide expansion of its energy-efficiency pilot program.

Utilidata has developed technology that lowers the voltage of electricity from substations to distribution lines. In 2013, Utilidata and National Grid signed a $500,000 deal for installation of the technology on its lines in Smithfield.

For this new agreement, the state Public Utilities Commission will need to approve the cost of equipment before National Grid can spend money, said David Graves, utility spokesman. The projected cost will be included in public documents when National Grid files its capital-expenses budget anticipated in late November, Graves said.

More: Providence Journal

SOUTH DAKOTA

PUC Schedules Hearing on Wind Power Price Dispute

The state Public Utilities Commission has scheduled an evidentiary hearing for April 11-14 to determine what price NorthWestern Energy should pay for electricity from three of Juhl Energy's wind farms.

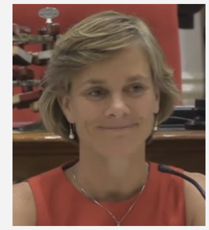
Under the Public Utility Regulatory Policies Act, NorthWestern must purchase the electricity — but the companies sharply disagree as to the purchase price, which is supposed to be equal to what the NorthWestern would pay for the power through its own generation or bought from another source. Juhl calculated $60.70/MWh, while NorthWestern calculated $24.35/MWh.

The commission is willing to pay up to $38,000 to an outside consultant to assist with the pricing analysis.

More: Rapid City Journal

VERMONT

Governor Candidates Differ on Where They'll Go for Energy


Minter

Both major candidates for governor say they want to achieve the state's goals of meeting 90% of its energy needs from renewable sources by 2050 — but differ sharply on where they won't go for energy.

Republican Phil Scott said during a televised debate that he would veto any bill calling for a tax on carbon-based fuels. He also does not want to see more wind power turbines on the state's mountaintops.

Democrat Sue Minter said during the debate that she would not rule out a carbon tax to reduce emissions if other Northeastern states joined in. She does not want more fossil fuel pipelines, but she has said a new technology for "decarbonized natural gas" under development by a California utility could possibly change her position.

More: The Associated Press