RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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All Zones at $1.50/MW-day in 5th MISO Capacity Auction

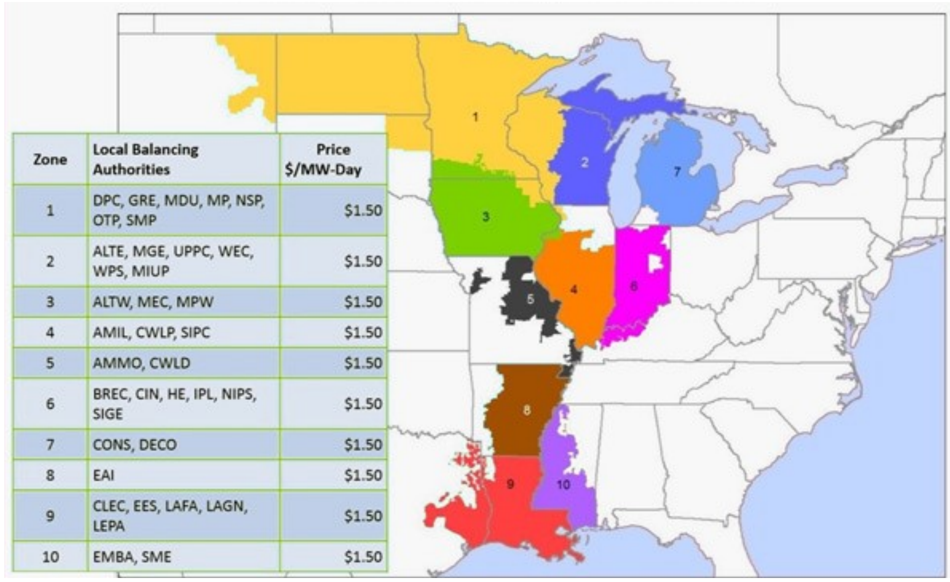
By Amanda Durish Cook

All 135 GW worth of capacity procured across 10 local resource zones in MISO's fifth annual Planning Resource Auction cleared at $1.50/MW-day, a vast departure from the regional disparities of the last two years, when prices rose as high as $150.

MISO said the results for planning year 2017/18, which begins June 1, are reflective of new supply and lower demand in the Midwest.

"The 2017-18 auction results reflect a net regional increase in supply compared to last year's results," said Richard Doying, MISO executive vice president of operations. "Even as the generation fleet continues to evolve, the level of available resources posi-

Continued on page 17



Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$1.50
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$1.50
3	ALTW, MEC, MPW	$1.50
4	AMIL, CWLP, SIPC	$1.50
5	AMMO, CWLD	$1.50
6	BREC, CIN, HE, IPL, NIPS, SIGE	$1.50
7	CONS, DECO	$1.50
8	EAI	$1.50
9	CLEC, EES, LAFA, LAGN, LEPA	$1.50
10	EMBA, SME	$1.50

2017/2018 auction clearing price overview | *MISO*

Texas Commission Denies NextEra's Bid for Oncor

By Tom Kleckner

From left to right: Texas Public Utility Commissioners Ken Anderson, Donna Nelson and Brandy Marty Marquez | *© RTO Insider*

The Texas Public Utility Commission on Thursday formally rejected NextEra Energy's proposed acquisition of Oncor, unanimously approving an order denying the $18.7 billion deal.

The PUC telegraphed the decision during its previous open meeting March 30. All three commissioners made it evident then that they believed the risks posed by NextEra's ownership outweighed the benefits. (See *Texas PUC Puts Brakes on NextEra's Oncor Acquisition*.)

Little changed Thursday.

"NextEra Energy ownership of Oncor would subject Oncor and its ratepayers to significant new risks," the PUC said in the order. "The tangible benefits to Texas ratepayers that are specific to the proposed transactions are minimal and would do little to compensate ratepayers for any of the additional risks imposed.

"When the commission weighs the additional risks and the lack of tangible benefits … the commission finds that the proposed transactions are not in the public interest."

Continued on page 9

Court Rejects FERC ROE Order for New England

By Rich Heidorn Jr.

An appellate court on Friday overturned FERC's 2014 order setting the base return on equity for a group of New England transmission owners at 10.57%, saying the commission failed to meet its burden of proof in declaring the existing 11.14% rate unjust and unreasonable.

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In this Week's Issue

Correction

An article in the March 14 newsletter, *PAR Wars: A Struggle for Power*, incorrectly reported that the phase angle regulators on the 5018 line at the Ramapo substation were part of the Con Ed-PSEG wheeling service that is ending April 30. The Ramapo PARs were not part of the wheel.

RESISTANCE
BY STEVE HUNTOON

Electric Infrastructure: Sky Keeps not Falling


Huntoon

Every four years, the American Society of Civil [not Electrical] Engineers releases its Chicken Little report on American infrastructure.[1] The report says our energy infrastructure — the second largest category after roads and bridges — should get a D+.

I don't know if the rest of the infrastructure sky is falling,[2] but when it comes to electric infrastructure, most everything in the report is wrong.[3]

[See ASCE's response on page 4.]

For starters, there is this claim: "With more than 640,000 miles of high-voltage transmission lines across the three interconnected electric transmission grids … the lower 48 states' power grid is at full capacity, with many lines operating well beyond their design."

The fact is that 0 (zero) transmission lines are being operated beyond their design capacity. The grid has been and continues to be designed and constructed to cover projected peak demand years in advance. And every line is operated within its design limits. The ASCE claim is alarmist and wrong.

Then there is this: "Often a single line cannot be taken out of service to perform maintenance as it will overload other interconnected lines in operation."

Hello, this is why most maintenance is performed in off-peak months — as has been done for decades.

And this: "As a result of aging infrastructure, severe weather events, and attacks and vandalism, in 2015 Americans experienced a reported 3,571 total outages, with an average duration of 49 minutes."

Whoa! "Total outages" is outages, large and small, across the entire country. The total number of people claimed to be affected? More than 13.2 million out of America's 325 million population.[4] The average number of people affected per outage? 3,714. Yes, less than 4,000 people per outage. For an average duration of 49 minutes.

And what portion of these 3,571 outages is even attributable to allegedly overloaded infrastructure, the gravamen of the ASCE report? According to ASCE's own data, a mere nine (yes, nine) outages are attributed to "overdemand."[5] Major outage causes are weather and trees at 1,069, faulty equipment and human error at 942, vehicle accidents at 419, squirrels at 89, etc.

So much for the present.

As for the future, the report relies on an obsolete projection of future electric demand. Increased efficiency and distributed energy resources, among other factors, have caused the U.S. Energy Information Administration to halve projected growth between 2016 to 2025, from ASCE's assumed 8% to the current 4%.[6] Using ASCE's methodology, it means "needing" $467 billion instead of $934 billion over the next 10 years.

ASCE projects spending of $757 billion, so under ASCE's own methodology, using the current EIA growth projection, we will be spending hundreds of billions *more* than we need to.

There's more. Buried in the study is an implicit assumption that the efficiency of electric generation is static; in other words, the capital cost of generating electricity remains constant, so we have to keep deploying the same dollars of investment per unit of increased electric demand.

The fact is that competitive market forces inexorably force down costs and thereby prices. Recent years have seen significant increases in the efficiency of natural gas generation and reductions in the cost of new electric generation capacity.[7] In other words, we are generating more electricity per dollar of capital investment.

Finally, the report doesn't recognize differences in how infrastructure decisions are made in this county. Other infrastructure, such as roads and bridges, do compete with other governmental spending priorities in political decisions by federal, state and local elected officials.

Electric infrastructure investment is not a political decision. It is determined by long-term planning criteria overseen in large part by independent regional (RTOs) and national (NERC) organizations, that in turn are overseen by an independent, highly regarded federal agency (FERC).[8]

Our electric infrastructure deserves an A.

Let's save the D+ for the ASCE report.

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


Transmission tower near Palm Springs, Calif. | © *RTO Insider*

[1] http://www.infrastructurereportcard.org/wp-content/uploads/2016/10/2017-Infrastructure-Report-Card.pdf.

[2] For critiques of the "roads and bridges are crumbling" theme, see http://www.npr.org/sections/itsallpolitics/2015/07/23/425292193/surprise-americas-roads-are-improving and http://www.economicpolicyjournal.com/2016/08/donald-trump-and-perennial-myth-of.html?m=1.

[3] This column reprises an article I coauthored 15 years ago, "The Myth of the Transmission Deficit," https://www.fortnightly.com/fortnightly/2003/11/myth-transmission-deficit. Fifteen years later the sky keeps not falling. More recently I've explained why big transmission is a big mistake. http://www.energy-counsel.com/docs/The-Rise-and-Fallof-BigTransmission-Fortnightly-September2015.pdf.

[4] https://powerquality.eaton.com/About-Us/News-Events/2016/PR100316.asp. Eaton, an electric equipment maker, is the source of the ASCE outage information.

[5] https://www.switchon.eaton.com/pdf/journey/business-continuity/cost-and-causes-of-downtime-infographic.pdf.

[6] EIA's 2017 Annual Energy Outlook projects electricity sales in 2025 of 3,892 billion kWh, which is about a 4% increase over 2016 sales of 3,727 billion kWh.

[7] "Heat rate" (Btu per kWh) declines for natural gas units are shown here: https://www.eia.gov/electricity/annual/html/epa_08_01.html.

[8] There are some states where reliability is more state-overseen than federal. Yes, state commissions face some political pressure to keep rates down … but even more to not have outages.

Stakeholder Soapbox

America's Energy Infrastructure: Room for Improvement

By Chuck Hookham, Otto J. Lynch and Adrienne Nikolic

The American Society of Civil Engineers' 150,000 members design, build, operate and maintain infrastructure in the U.S. and globally. While roads and bridges are often the first thing to come to mind when hearing the word "infrastructure," civil engineers also ensure Americans have access to reliable, low-cost energy from its roots (oil/gas wells, electric generation, etc.) to its delivery at the pump or outlet. As an example, each transmission line is essentially a suspension bridge of steel, concrete, wood, cable and other materials, requiring surveying, site work, foundations, structures and construction — all areas of expertise for civil engineers, working in conjunction with other engineering disciplines.

Who better to assess the health of the nation's energy infrastructure than civil engineers?

That's why, since 2001, ASCE's Infrastructure Report Card has included energy infrastructure, with particular emphasis on electricity transmission and distribution infrastructure. Released every four years, the Report Card follows the familiar A-to-F format of a school report card, grading 16 categories of infrastructure. Prepared by a team of civil engineers with expertise across all categories, the Report Card serves as an unbiased, go-to source for information on the state of the nation's infrastructure, and has been cited by U.S. presidents, countless elected officials at all levels of government, academics and media outlets.

Unfortunately, much like the overall grade across all 16 categories, the energy grade has been stalled in the D's. In the 2017 Report Card, ASCE graded the nation's infrastructure a D+ and energy also received a D+ — both the same as in 2013.

To determine the grades, we assess relevant data and reports, consult with technical and industry experts, and assign grades using the following key criteria: capacity, condition, funding, future need, operation and maintenance, public safety, resilience and innovation.

While U.S. energy systems are sufficient to meet the country's projected energy needs, the 2017 Report Card highlights both issues of concern and potential solutions. Most existing power lines were constructed in the 1950s and 1960s with a 50-year life expectancy, meaning they were not designed to meet today's significant demand or the evolving need to integrate distributed energy resources. While projections for energy consumption indicate only modest increases between 2015 and 2040,[1] the country still faces significant challenges in ensuring energy is available where it is needed, including transmitting energy from renewable sources to population centers. We cannot build a new wind farm in Kansas and expect the power to just magically appear in New York.

Aging lines and equipment in America's multiple power grids are operating well beyond their designed maximum operating temperature and peak load, and congestion creates transmission constraints for delivering power from remote generation sites to areas of demand, also affecting reliability and cost of service.[2] NERC's standards for tree clearance and vegetation only go so far when confronting increasing extreme weather events and exposure to human threats. And just as one closed road causes traffic jams, one power line outage can affect transmission and distribution to millions. Because of a lack of storage and near constant demand, the interruption of any energy system is immediately felt by the user.

While there are certainly more potholes in America's roads than there are estimated power outages each year, loss of electric power or gas flow through a major pipeline causes a ripple effect on Americans' daily lives and the economy. The U.S. energy system is the critical infrastructure that keeps America's lights on, transportation moving and information flowing. Yet the current system in many parts of the country is not adequately resilient and efforts to change that through investment and improvement are highly politicized, often caught up in larger debates about climate change, fuels and national security.

As part of the Report Card, ASCE also commissioned an independent economic analysis of the investment needs and consequences across 10 sectors of infrastructure, including electricity, by a well-respected economic research group. The series, titled "Failure to Act," was first released in 2011 but was updated in 2016.[3,4] The 2016 study examines the investment needs, projected funding and remaining gap for building new infrastructure as well as maintaining or rebuilding existing infrastructure. The analysis also presumes the mix of generation technologies and sources continues to evolve, resulting in new efficiencies and approaches for meeting demand. The study concluded that in electricity, while the investment gap totals $177 billion between 2016 and 2025, more than 80% of the total infrastructure investment needs are projected to be funded, thanks in no small part to the significant involvement of the private sector in the nation's energy systems.

No American who has experienced an extended electrical outage, lost appliances because of a power surge or seen downed wires in their neighborhood would grade our electric infrastructure an A, nor do the engineers who design, build and desire to maintain that infrastructure day in and day out.

Chuck Hookham, P.E., M.ASCE, is director of NBD services at CMS Energy, a large regulated electric/gas utility and non-regulated developer of energy projects, headquartered in Jackson, Mich. He has more than 35 years of experience in power generation, transmission and distribution, natural gas and oil pipelines and refineries, and infrastructure systems, and is a member of the ASCE Committee on America's Infrastructure, which prepared the 2017 Infrastructure Report Card.

Otto J. Lynch, P.E., F.ASCE, F.SEI, is vice president of Power Line Systems Inc. in Nixa, Mo. For more than 28 years, he has participated in the design and construction of numerous high-voltage transmission line projects around the world and was a pioneer in the use of LiDAR in the transmission line industry. He is a member of the ASCE Committee on America's Infrastructure, which prepared the 2017 Infrastructure Report Card.

Adrienne Nikolic, P.E., M.ASCE, is an energy and utilities consultant based in Philadelphia, Pa. She is responsible for assisting energy and utility clients with the management of projects that modernize the grid, and is a member of the ASCE Committee on America's Infrastructure, which prepared the 2017 Infrastructure Report Card.

[1] U.S. Energy Information Administration Annual Energy Outlook 2017. https://www.eia.gov/forecasts/aeo/executive_summary.cfm

[2] U.S. Department of Energy. Quadrennial Energy Review Energy Transmission, Storage, and Distribution Infrastructure. 2015. http://energy.gov/sites/prod/files/2015/08/f25/QER%20Summary%20for%20Policymakers%20April%202015.pdf

[3] American Society of Civil Engineers. Failure to Act: The Economic Impact of Current Investment Trends in Electricity Infrastructure. 2011. http://www.asce.org/electricity_report/

[4] American Society of Civil Engineers. Failure to Act. 2016. http://www.infrastructurereportcard.org/the-impact/failure-to-act-report/

California to Reconsider Retail Choice

By Robert Mullin

More than two decades after initiating a deregulation drive that faltered in the wake of the Western Energy Crisis of 2000/01, California officials are taking another look at offering consumers the ability to choose their electric supplier.

This go-round should be different, according to the state agencies heading up a new exploration of "the changing state of retail choice" in California, because of changes already in motion.

"Unlike electricity restructuring efforts of the past, when policymakers made a set of conscious decisions to move to open market competition, this transition is being driven by a range of economic and technological trends," the California Public Utilities Commission and California Energy Commission said in a joint statement April 11.

To kick off the effort, the two agencies will hold a May 19 joint *en banc* public hearing to identify the "challenges and opportunities" stemming from "fast-approaching" changes overtaking the industry. The goal is "to ensure that reliable and low-carbon electricity will be available to all California consumers," the agencies said.

Key among the factors now influencing the sector: the rapidly falling costs for renewable and energy storage technologies, which the CPUC and CEC say are "upending the nature of electricity service."

The agencies estimate that by the end of this year, up to 40% of the state's investor-owned utility customers will be receiving "some type" of electricity service from an alternative source, such as rooftop solar, community choice aggregators (CCAs) and direct access providers.

California today boasts nearly 5,200 MW of installed rooftop solar capacity, according to California Distributed Generation Statistics, a website sponsored by the CPUC and the state's IOUs. The state also has six CCAs, with more slated to begin operation within the next few years, a development that is expected to increasingly siphon off the customer base from the traditional IOUs.

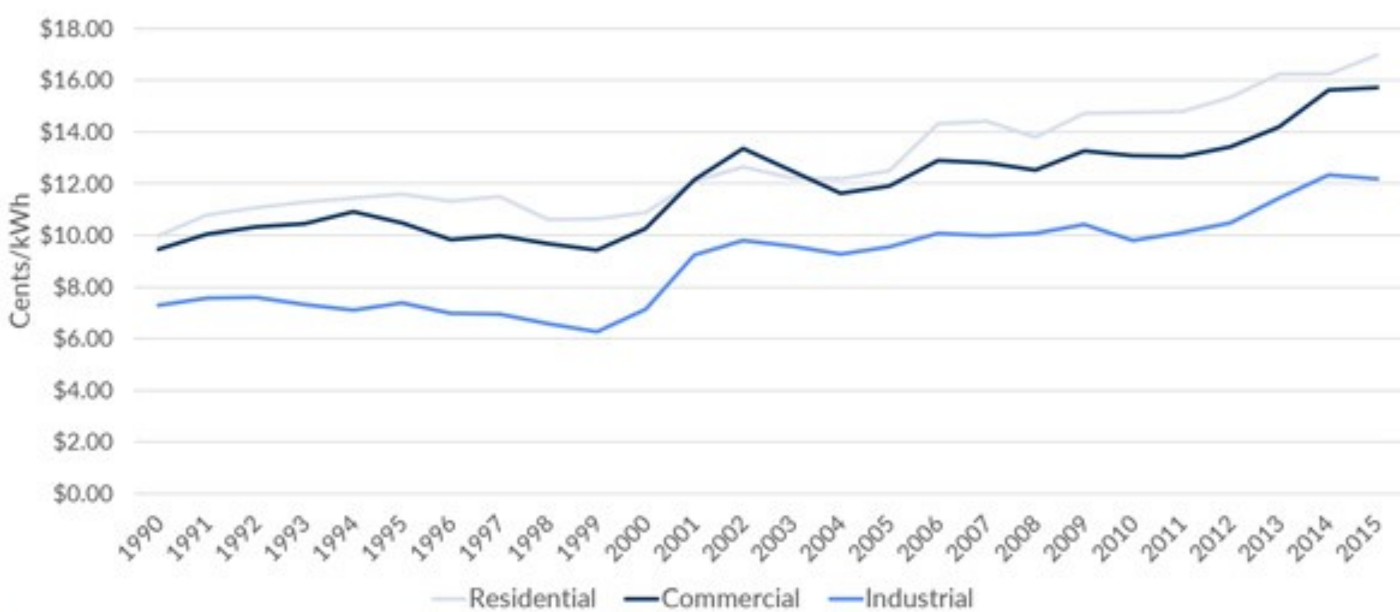
"The implications of this migration away from 'bundled' utility service were not fully contemplated when the current regulatory rules were developed," the agencies said.

The changes provide "tremendous opportunities" for California to meet its carbon reduction goals, but they will also create "unforeseen risks," the agencies said.

The May 19 hearing will offer a closer examination of those opportunities and risks. A preliminary agenda indicates the event will start with a presentation on a still-pending CPUC white paper on retail choice, followed by an overview of the current state of retail choice in California and panel discussions focused on the perspectives of both the IOUs and electricity customers.

The agencies will also invite national electricity market experts to share their perspectives on retail choice in other regions, the role of technology in transforming electricity service and how California can restructure its regulatory framework and markets to help achieve its public policy goals.

California last set a course for deregulation in 1996 with the enactment of Assembly Bill 1890. Under the law, regulators first set out to restructure the state's wholesale market while leaving retail price controls intact. The ensuing crisis — which resulted in the 2001 bankruptcy of wholesale market operator California Power Exchange — precluded the implementation of any retail market measure. Wholesale operations now reside with CAISO, which in 2009 rolled out a nearly statewide energy market designed to prevent the kind of manipulation that crippled the exchange.



California officials are reconsidering the idea of "consumer choice" for retail electricity customers who continue to pay some of the highest rates in the country. Efforts would focus on giving more residents affordable access to renewable resources that help the state meet its environmental mandates. | *U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."*

CAISO NEWS

Western Regulators Supportive of EIM Charter Changes

By Robert Mullin

Western state utility commissioners last week expressed support for providing the Energy Imbalance Market (EIM) Governing Body with increased authority over changes to the market's governing charter.

The commissioners also agreed on a set of measures that would streamline the process for convening calls and meetings of their own EIM-related group, the Body of State Regulators (BOSR).

BOSR members were scheduled to hold a nonbinding vote on whether to endorse the charter revisions during the April 10 teleconference, but the group fell two members short of a quorum, which requires the presence of commissioners from five of the eight states in the EIM footprint.

In an April 5 memo, CAISO management proposed that any "substantive" modifications to the charter be first presented to the Governing Body for its "advisory" input — similar to the role body members play regarding ISO market rule changes that also affect the EIM. (See *EIM Charter Changes Would Give Governing Body More Power*.) The ISO initiated the move at the request of Governing Body Chair Kristine Schmidt.

Other revisions would enable the Governing Body to initiate changes to portions of the charter dealing with the BOSR and the Regional Issues Forum.

The Governing Body plans to present the changes to the CAISO Board of Governors, which is charged with reviewing any charter amendments during its May meeting. The board must formally approve any changes to the charter, but in practice it gives wide latitude to the Governing Body's decisions on solely EIM matters. Timelines dictate that the amendments will advance without the BOSR's formal endorsement, which is not required.

The state commissioners who spoke last week's call voiced their informal support for the changes. No one expressed any opposition. They were relying, in part, on the advice of the commissions' staffs.

"The official recommendation from the Advisory Committee is that you approve and support [the changes] to the Governing Body," said Brian Thomas, policy director with the Washington Utilities and Transportation Commission and a member of the EIM Staff Advisory Committee.

Thomas noted that WUTC Commissioner and BOSR Chair Ann Rendahl — who couldn't participate in the call because of a schedule conflict — supported the changes.

Changes 'Make Sense'

Utah Public Service Commissioner Jordan White agreed with the staffs' recommendation and the CAISO memo outlining the changes.

"It makes sense," White said. "It's consistent with how the charter works in terms of certain issues that go to [the] consent [agenda] of the full Board of Governors."

"I don't see any reason that we would oppose it, but it sounds like we're not making any decision today, so I'll take a look and get back with everyone," said Oregon Public Utility Commission Chair Lisa Hardie.

White apologized to Schmidt for his group's inability to provide full approval.

"Thank you very much for going ahead with the discussion," Schmidt replied. "Because if there were some issues or concerns that any of the Body of State Regulators would have, we would want to know about that."

The submission of a written recommendation from the Advisory Committee would be helpful to the Governing Body in its own deliberations, she added.

"I can write something up that summarizes what the staff committee did and recommended and provide that to you," Thomas responded.

Speaking on behalf of the BOSR, White told Schmidt: "We appreciate the opportunity to at least have a say in this."

'Willingly Pay'

Commissioners also backed proposals to allow CAISO to post BOSR meeting agendas on the ISO's website and to use its audio conferencing system to host calls.

Among those voicing support for the move was White, who pointed out that Rendahl and her WUTC staff had been "carrying the water" of setting up the agendas and conducting BOSR meetings.

"We had reached out to [Rendahl] and mentioned that we would be happy to host and just try to take some of that administrative burden off of the group," said Peter Colussy, CAISO external affairs manager.

"I think we're comfortable with that," Hardy said. "It seems like that would functionally work just fine from our perspective."

"Speaking for the Washington staff that's been doing this, we would willingly pay CAISO to take over this stuff," Thomas joked.

The commissioners also endorsed the idea of subsuming the BOSR's infrequent in-person meetings into those held by the EIM Governing Body.

"I think the jury is still out on how often to have [BOSR] meetings," White said.

Because of the lack of quorum during the April 10 call, the meeting-related proposals were tabled by the BOSR until its next call on May 30.

CAISO NEWS

EIM Panel Backs Schmidt for 2nd Governing Body Term

By Robert Mullin


Schmidt

A Western Energy Imbalance Market (EIM) nominating committee made up of regional stakeholders is recommending that Kristine Schmidt be reappointed to the market's Governing Body.

Schmidt was selected by the inaugural Governing Body last June after an extensive vetting process that included deliberations among five industry sectors: EIM entities, ISO participating transmission owners, power suppliers and marketers, publicly owned utilities, and state regulators. (See *CAISO Board Appoints Western Energy Imbalance Market Governing Body*.)

"The committee deliberated, as well as conducted outreach to its respective sectors, and reached consensus that it wished to renominate member Schmidt," the nominating committee said in a memo to the Governing Body.

While Governing Body members are typically appointed for three years, the EIM's charter calls for their terms to be staggered. Last year, a random selection process left Schmidt with what was essentially the short straw: a one-year stint slated to end this July. Schmidt's fellow body members elected her to be the group's chair during the group's first meeting last August. (See *EIM Governing Body Convenes First Meeting, Selects Leadership*.)

"While quite grateful for this first one-year term … I firmly believe that given the forecasted EIM market and policy changes and the expansion opportunities, I have much more to offer the Western EIM and Governing Body to realize the mission of promoting, protecting and expanding the EIM," Schmidt wrote in a Jan. 26 letter to the nominating committee.

Schmidt's brief time on the Governing Body has seen the group perform myriad functions, including reviewing the EIM's governance structure, initiating outreach to Western utility commissions and EIM members, participating in the self-evaluation of the Regional Issues Forum, and dealing with two CAISO initiatives in the group's "advisory" capacity to the ISO's Board of Governors.

In her letter, Schmidt noted that the body expects to rule on nine decisional matters this year. Most of those decisions are slated to land on the agenda starting in the third quarter.

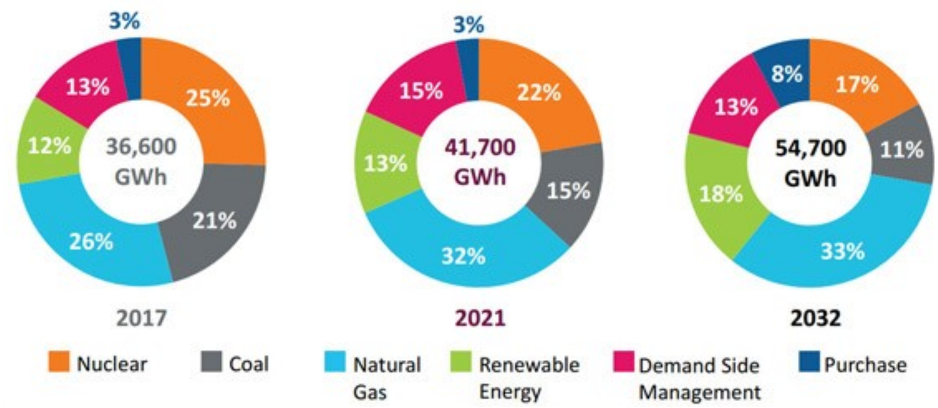
"With a substantial workload pending for the latter half of 2017, I believe the experience and knowledge gained thus far will prove vital when deliberating over these decisional and advisory policies, as well as future polices in 2018 and beyond," Schmidt wrote. Her fellow Governing Body members will vote on her reappointment during the group's April 19 meeting.

Schmidt is currently president of Dallas-based Swan Consulting and has more than 30 years' experience in the energy sector. She was formerly vice president at ITC Holdings and director at Xcel Energy. She has also worked as an adviser to former FERC Commissioner Nora Brownell.

CAISO NEWS

Gas, Solar, Efficiency Nudge Coal in Arizona Public Service IRP

By Robert Mullin



Energy mix of APS 2017 IRP (flexible resource portfolio) | *APS*

Arizona Public Service expects to meet its future energy needs through increased use of natural gas, solar and efficiency measures, while at the same time reducing its reliance on coal-fired generation, according to the company's 15-year integrated resource plan.

The IRP filed with the Arizona Corporation Commission predicts the utility will face a deepening "duck curve" — such as that already witnessed in California — as households within its service territory ramp up adoption of non-curtailable rooftop solar resources.

Still, APS sees a continued, if reduced, role for its 1,146-MW Palo Verde nuclear plant located near Phoenix, which the company refers to as the country's "largest carbon-free resource."

The IRP calls for APS to rely on solar resources and energy efficiency to meet 50% of projected demand growth in its service territory by 2032, when the utility's peak capacity requirements are expected to reach 13,000 MW, a 61% increase from the current 8,086 MW. The plan assumes that Arizona's population will grow to more than 9 million from around 6.9 million today, adding 550,000 customers to the utility's service area. The state's Office of Economic Opportunity population projection falls short of APS' 2032 estimate at just less than 8.8 million.

"We do have some concerns with [APS's] numbers but haven't come to any conclusions yet," Ken Wilson, an engineering fellow with Western Resource Advocates, told *RTO Insider*. Wilson noted that he's participated in several preliminary workshops in which the utility presented its projections for load growth.

To achieve its goal of using renewables and efficiency to address half of that expected future growth, APS has proposed what it calls a "flexible resource portfolio," that reduces carbon emissions through "select coal reductions," more demand-side management and "a prudent level of energy storage," while continuing to add renewables and operate Palo Verde.

Over the planning period, natural gas generation is expected to increase from 26% to 33% of the utility's energy mix, while utility-scale renewables grow from 12% to 18%.

The utility also expects to offset peak load with an additional 979 MW of demand-side resources, which includes demand response and energy efficiency.

Coal-fired capacity would decline by 702 MW (42%) to 970 MW, accounting for 11% of the energy mix, down from 21% today. Output from Palo Verde is slated to hold steady, but the plant's share of the mix would drop from 25% to 17%.

Market purchases are forecast to rise from 3% to 8% as the company retires coal and rolls off existing power contracts.

"APS will continue to pursue opportunities to increase operating efficiency and save customers money, such as participating in the CAISO Energy Imbalance Market and purchasing excess energy from short-term markets at low or negative (i.e., paid to take) prices," the company said in a statement.

APS estimates that its CO_2 emissions and water consumption per unit of electricity will decline by 23% and 29%, respectively.

"Overall, our energy mix is increasingly cleaner, and we are adding more quick-starting power sources to integrate our growing solar energy resources and emerging technologies," said Tammy McLeod, APS vice president of resource management.

Key among those technologies is energy storage, the deployment of which is expected to climb from 4 MW to 507 MW over the next 15 years.

The IRP points to the adoption of rooftop solar as "one of the single most defining factors in western energy markets today," given its tendency to displace the output of other resources, create volatility in wholesale power prices and increase the need for fast-ramping natural gas plants and resources serving local load pockets.

APS expects rooftop installations within its territory to nearly double by 2032 to 4,998 MW, precipitating a deepening of a duck curve that could push "net loads" — the portion of system load served by non-variable resources — to as low as 500 MW, which will create ramping requirements of between 4,000 and 5,000 MW.

In response, the company plans to upgrade its operational flexibility, including the modernization of its Ocotillo Power Plant with five quick-start natural gas-fired units. APS also plans to invest in technologies that increase real-time visibility into the utility's distribution system and implement a new Demand Response, Energy Storage, Load Management program to help residential customers manage energy use.

"Increasing renewable resources, energy efficiency and energy technologies, supported with highly responsive resources such as natural gas generation, will enable APS to deliver cleaner, reliable and reasonably priced electricity," McLeod said.

ERCOT News

Texas PUC Chair Nelson Stepping Down

By Tom Kleckner


Nelson

Texas Public Utility Commission Chair Donna Nelson surprised staff and open-meeting attendees Thursday by announcing she would be stepping down in May.

Nelson was appointed to the PUC by Gov. Rick Perry in August 2008. She was named chairman in July 2011 and was appointed by Gov. Greg Abbott to another six-year term in September 2015 that was to expire in September 2021.

"I think you have left a distinguished and wonderful mark on this state with your service," Commissioner Brandy Marty Marquez told Nelson after her announcement. "There's a whole lot of gratitude owed to you, by everybody here."

"I'm not dead yet," Nelson responded, before getting down to business. "It's been a great time and we've done a lot of important things, so let's continue that work now."

Nelson, who said her last day will be May 15, will leave the PUC having served more time than anyone else. However, Commissioner Ken Anderson could soon eclipse her tenure. He joined the PUC one month after Nelson did, and his current term expires in August.

Marquez was appointed to the commission in August 2013. Her six-year term expires in September 2019.

Nelson said she would elaborate on her future plans as her end date nears.

Abbott will appoint Nelson's replacement as chairman, as well as fill the commission's vacancy. The PUC oversees ERCOT and Texas electric, telecommunication, water and sewer utilities.

Nelson also represents the PUC on SPP's Regional State Committee, which provides regulatory input to the RTO. She will be replaced on the RSC by one of her fellow commissioners.

Ironically, Nelson, who is not a fan of personal photos, also said she had "good news": "I'm getting my portrait taken."

Her official studio photo will finally join those of the other current and previous commissioners on the PUC's hearing room's walls.

Before joining the PUC, Nelson was a special assistant and adviser to Perry on energy and telecommunication issues. She also served as legal adviser to a previous PUC chairman and as a former assistant attorney general for Texas, where she specialized in antitrust law.

A South Dakota native, she received a bachelor's degree from Black Hills State College and a law degree from Texas Tech University.

Texas Commission Denies NextEra's Bid for Oncor

Continued from page 1

The commission noted NextEra's proposal "is premised on the ability to link Oncor's credit profile with that of NextEra Energy," and that the Florida company objected to removing two protections from Oncor's existing ring fence: restrictions on NextEra's ability to appoint and replace members of Oncor's board of directors, and the board's ability to limit dividends or other "upstream distributions" from Oncor.

The PUC said those two ring-fence provisions had insulated Oncor from parent Energy Future Holdings' bankruptcy. It said "a truly independent" board with control over decisions on capital expenditures and operating expenses is a "critical part of the ring fence."

NextEra and Oncor declined to comment on the order and future steps, as they have done throughout the process.

NextEra proposed last summer to purchase Oncor in three transactions:

- The approximately 80% interest indirectly held by EFH;
- The 19.75% interest indirectly held by Texas Transmission Holdings Corp.; and
- The 0.22% interest held by Oncor Management Investment.

The PUC considered all three transactions as one. It said NextEra's "expansive and diversified structure" would subject Oncor to "new and potentially substantial risks." It said NextEra would be refinancing current debt with new debt, making Oncor responsible for supporting 15% of $45 billion in consolidated obligations.

The commission approved the order before gathering in public Thursday, but brought it up briefly during the open meeting to substitute the word "difficulties" for "calamity" in a reference to how "a robust ring fence" protected Oncor's ratepayers from the impact of EFH's bankruptcy.

It was the second failed attempt to acquire Texas' largest transmission and distribution service provider in less than a year. Dallas-based Hunt Consolidated withdrew its application with the PUC last May over requirements it found too onerous. (See *Texas PUC Denies Rehearing on Oncor Sale, Ends Hunt Bid*.)

Oncor has been ring fenced since 2007, when EFH, a collaboration of several private-equity firms, acquired TXU Corp. in a leveraged buyout. EFH, saddled by nearly $50 billion in debt when it bet wrong on high gas prices, declared Chapter 11 bankruptcy in 2014. It has since spun off its generation and retail electric service providers as Vistra Energy.

NextEra's proposed acquisition was part of EFH's eighth amended plan of reorganization, which was confirmed by a bankruptcy court in Delaware in February. That court held another hearing on the case Monday, where lawyers for NextEra indicated that the company may challenge the PUC's decision.

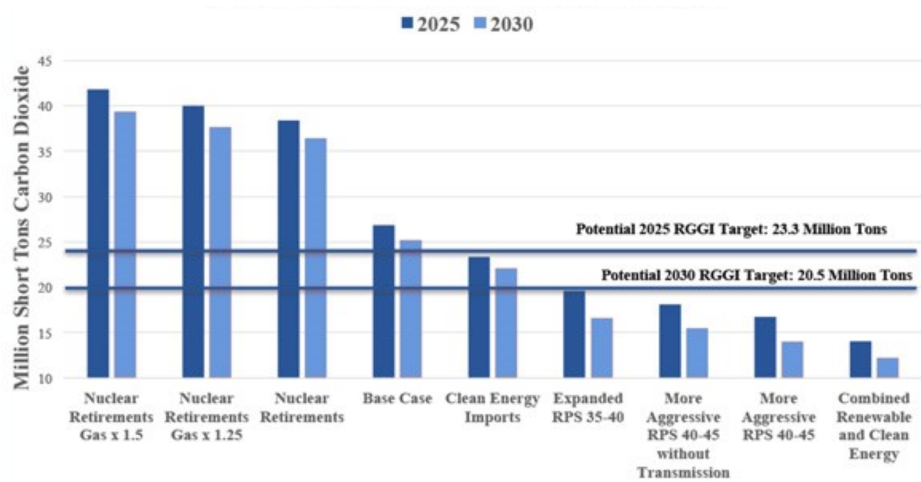
NextEra shares fell briefly to $130.22 after the commission's meeting opened, before recovering to close at $130.79. The company's stock has gained more than $11/share since the year began.

ISO-NE NEWS

New England Study: More Wind, Tx Needed to Meet RPS Targets

Releases Renewable Scenario Analysis Ahead of FERC Conference

By Michael Kuser



Forecasted power sector carbon emissions | *NESCOE*

New England states will not have enough renewable resources to meet the 2025 and 2030 targets in current renewable portfolio standards without adding transmission for new onshore wind, according to a scenario analysis conducted for the New England States Committee on Electricity.

NESCOE's Renewable and Clean Energy Mechanisms 2.0 Study used a model from London Economics to evaluate the impact of five scenarios on prices, emissions and "missing money" — the potential gap between generators' revenues and their operating costs.

ISO-NE officials provided a briefing on the Phase I findings — part of the New England Power Pool's Integrating Markets and Public Policy (IMAPP) initiative — at the NEPOOL Participants Committee meeting on April 7.

The results are expected to be discussed at FERC's technical conference May 1-2 on tensions between state public policies and wholesale markets in ISO-NE, PJM and NYISO.

The study builds on NESCOE's December 2015 whitepaper, "Mechanisms to Support Public Policy Resources in the New England States."

One scenario that considered the accelerated retirement of the region's nuclear capacity included sensitivities based on natural gas prices. One that looked at more renewables and transmission considered several alternatives for expanded state renewable standards.

The study concluded that new renewable generation or additional clean energy imports to New England with very low marginal costs will cut energy and capacity revenues for all other resources. Nevertheless, the study noted that under every scenario considered, nuclear generators, existing oil combustion turbines, oil internal combustion turbines, oil steam and pumped storage

Continued on page 11

Maxim Power Sells US Assets to Hull Street Energy

By Michael Kuser

Alberta-based Maxim Power announced it has closed a deal to sell its U.S. subsidiary and its five generation plants, concluding a two-year effort to stave off threats to the company's survival.

Hull Street Energy, through its newly formed affiliate Milepost Power Holdings, paid $106 million for Maxim's 447 MW of power generation assets in the U.S., or about $238,000/MW of generating capacity. Three of the plants are dual-fuel combined cycle plants in New England, and the others are simple cycle natural gas turbines in New Jersey and Montana.

In May 2015, Maxim reported that it had breached several financial covenants with its Canadian bank and that "significant doubt may exist with respect to the ability of the corporation to continue as a going concern." The company said it was pursuing asset sales to improve its cash position.

The company's outlook was not helped later in May 2015 when FERC accused it of manipulating the New England power market in a fuel-switching scheme (IN15-4). Under a consent agreement approved with FERC's Office of Enforcement last September, Maxim agreed to pay a $4 million fine and disgorge another $4 million in earnings to ISO-NE, but it did not admit guilt. (See *Maxim Power to Pay $8M to Settle Fuel-Switching Case*.)

The same month, Maxim sold 176 MW of generation assets in France, its COMAX subsidiary, to an affiliate of Basalt Infrastructure for 47 million euro ($52.8 million at the time), about $300,000/MW.

Maxim said it will use $8 million (CAD) of the proceeds from the sale of its U.S. assets as collateral for letters of credit and $5 million (USD) to fulfill the settlement agreement with FERC. The company, which trades on the Toronto Stock Exchange, reported $2.2 million in net income on $94.5 million in revenue for 2016.

The assets acquired by Milepost are the 181-MW Pittsfield plant that FERC identified in the fuel-switching scheme; the 87.2-MW Forked River plant in Ocean County, N.J.; a 63.5-MW plant in Pawtucket, R.I.; the 62.1-MW CDECCA plant in Hartford, Conn.; and the 54.9-MW Basin Creek plant in Butte, Mont.

ISO-NE NEWS

New England Study: More Wind, Tx Needed to Meet RPS Targets

Continued from page 10

will remain profitable in 2025 and 2030.

The study found that under base case load conditions, New England's addition of more than 25 million MWh annually of renewable resources and/or clean energy imports by 2025 would cause existing renewable and clean energy resources to produce less power.

If the region doesn't build new transmission to move power from new onshore wind to load centers, both new and existing onshore wind "will operate less often and earn less revenue in 2025 and 2030," the study said.

Unsurprisingly, it also concludes that the retirement of the region's nuclear generation would "significantly" increase carbon emissions, as would a failure to increase renewable capacity above current RPS levels.

Phase II of the study will test the operability of each scenario and assess additional market outcomes:

1. Natural gas pipeline constraints, to be discussed with the Planning Advisory Committee in the second quarter;
2. Forward Capacity Auction prices, also to be discussed with the PAC in Q2; and
3. Frequency regulation, ramping and reserves, to be discussed with the PAC in the fourth quarter.

FERC last week released the agenda for the May 1-2 technical conference (AD17-11).

Before the conference, ISO-NE plans to issue a summary of its "concept for accommodating additional state-subsidized resources and their associated pricing impacts on the capacity market." The New England Conference of Public Utilities Commissioners Symposium in Connecticut in May and the NEPOOL Participants Committee summer meetings may allow for additional dialogue on the concept, said Chief Operating Officer Vamsi Chadalavada.

ISO-NE likely will file any related proposals with FERC by the end of 2017 to allow for implementation ahead of FCA 13.

The grid operator also is evaluating fuel security issues and their effect on the bulk power grid and plans to discuss its findings with stakeholders during the second half of 2017.

ISO-NE Considers Accelerating Ramping Pricing Effort

Chadalavada also updated the Participants Committee on the Updated 2017 Work Plan, saying the RTO is considering accelerating its discussions of potential pricing approaches for resource ramping.

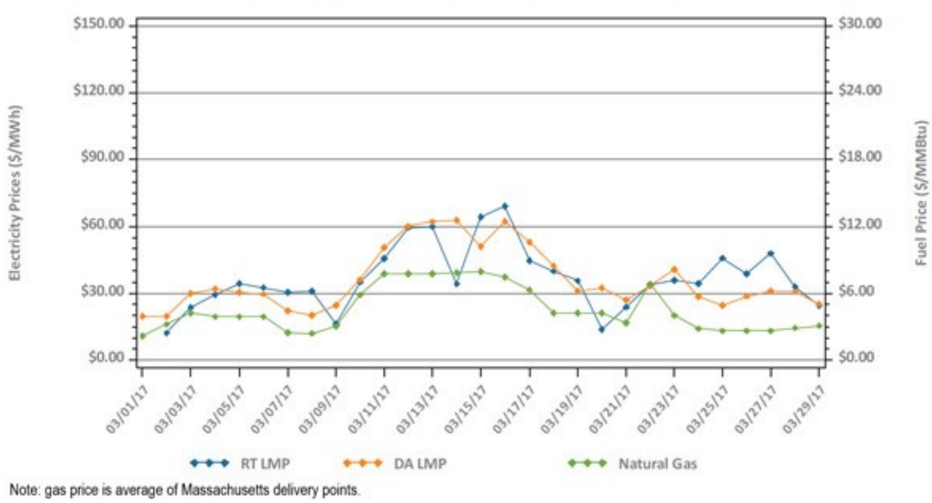
Previously, the grid operator had delayed the resource ramping assessment to follow both IMAPP and the day-ahead reserve market enhancement assessment. The RTO now plans to hold technical sessions on how ramping currently works and to survey how other regions are handling the issue by the fourth quarter of this year.

The COO also said ISO-NE's 2017 long-term load, energy-efficiency and solar PV forecasts are nearly complete. "The overall trend is lower net energy and seasonal peak demand for New England," Chadalavada said.

ISO-NE NEWS

Gas, LMPs Rebound in NY, New England in March

By Michael Kuser



Daily average day-ahead and real-time ISO-NE hub prices and input fuel prices: March 1-29, 2017 | *NEPOOL*

A spike in natural gas costs pushed LMPs up in both NYISO and ISO-NE in March, though analysts say the rise may be short-lived.

NYISO on Wednesday reported locational-based marginal prices for March averaged $34.97/MWh, up from $30.95/MWh in February 2017 and a 69% jump from the $20.66/MWh in March 2016. Year-to-date costs averaged $37.81/MWh through March, up 23% from $30.68/MWh a year earlier.

In his April 12 Market Operations Report to the Business Issues Committee, Rana Mukerji, NYISO senior vice president for market structures, said natural gas prices in March were up 169% year-on-year, with prices at Transco Z6 NY averaging $3.49/MMBtu for March, up from $2.83/MMBtu in February. Mukerji said five days of cold weather boosted prices for the month.

ISO-NE said its average LMPs more than doubled in March from a year earlier as average natural gas prices rose 142%.

The RTO said the energy market totaled $382 million in March, up 74% from March 2016, ISO-NE Chief Operating Officer Vamsi Chadalavada told the New England Power Pool Participants Committee on April 7. Cold weather and higher gas prices March 11-14 caused day-ahead LMPs to jump to nearly $100/MWh during the period, with real-time prices spiking as high as $150/MWh as a storm hit the region with near-blizzard conditions March 14.

Blip or Trend?

Are the higher natural gas prices just a blip, or do they portend higher generator costs going forward? Jordan Grimes, director of power and gas with Morningstar, said that "market sentiment is relatively bearish on

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MISO NEWS

MISO, IMM Differ over Scarcity Pricing Changes

By Amanda Durish Cook

MISO's Independent Market Monitor says the RTO isn't going far enough in proposing changes to comply with FERC's new energy offer cap rules.


Hansen

Chuck Hansen, MISO senior market engineer, told the April 13 Market Subcommittee meeting that the RTO will propose only "minimal" changes to its operating reserve demand curve (ORDC) in a filing planned for next month to comply with FERC Order 831, which requires the use of a $1,000/MWh soft cap and $2,000/MWh hard cap by winter 2017/18. MISO says the ORDC also must be changed because of new NERC reliability rules. (See *MISO Contemplates Market Design Changes from FERC Offer Cap Rule*.)

Monitor David Patton, however, told the committee that MISO should make broader changes, including an immediate increase in its maximum value of lost load (VoLL) calculation.

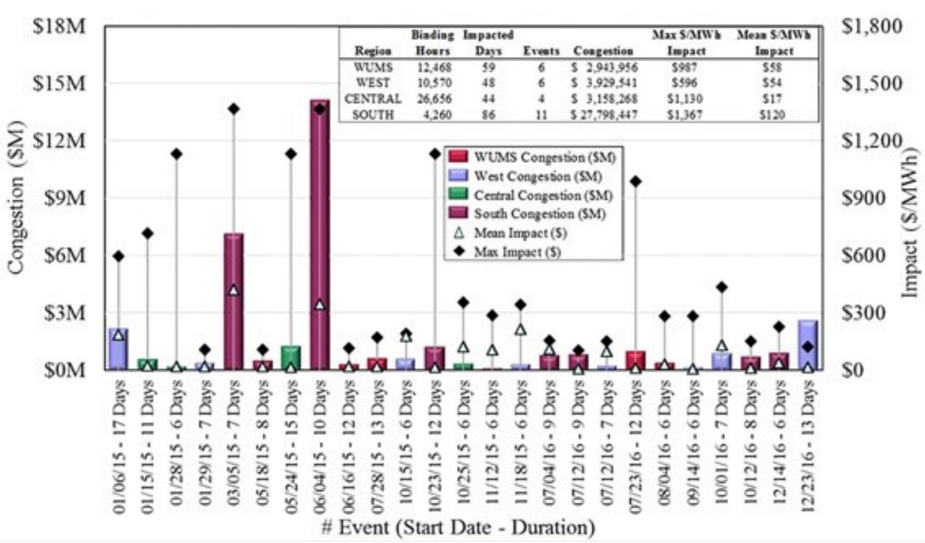
MISO's Step-Based Curve

MISO's current ORDC is step-based, dropping sharply from a $3,500/MWh maximum VoLL when less than 4% of the requirement level has cleared, to $1,100/MWh when more than 4% of the requirement clears. It then drops vertically to $200/MWh when 96% or more of the requirement is satisfied.

Under MISO's proposal, the new curve would begin at $3,300/MWh, dropping to $2,100/MWh when the RTO clears 8% of its requirement level, reflective of "extreme scarcity conditions," Hansen said. At 89%, the level falls to $1,100, remaining there until 96% or more of the requirement is cleared, when the curve flattens at $200.

Even as the top of the ORDC inches toward the maximum VoLL — currently the $3,500/MWh limit set in 2005 — Hansen said MISO won't recommend VoLL changes in its FERC filing. He acknowledged, however, that the maximum will have to be redone in the "near future."

"We're going to move forward with [refreshing the VoLL] subject to budget limits. We've got a lot of things going on right now, but assessing VoLL is not a trivial matter," MISO Executive Director of Market Design Jeff Bladen said.



MISO's Independent Market Monitor is again recommending the RTO expand mitigation measures on narrowly constrained areas by creating a new definition aimed at periods of temporary congestion. | *Potomac Economics*

MISO's deadline for filing the proposed changes is May 8. "We should be able to achieve that if everything goes as planned," Hansen said.

Order 831 caps incremental energy offers at the higher of $1,000/MWh or a resource's cost-based energy offer, with $2,000/MWh being the maximum bid. (See *New FERC Rule Will Double RTO Offer Caps*.)

MISO said its proposal won the broadest support from stakeholders of four options considered.

Patton Seeks Increase in VoLL

But Patton is recommending the RTO make immediate changes to its VoLL limit and change its ORDC calculation to a sloped curve that he contends would better price shortages. Patton said a VoLL cap of $9,000/MWh is reasonable based on past studies. The Monitor would set a VoLL of $1,000/MWh to reflect the demand curves for spinning reserves and regulation, and high marginal energy costs resulting from congestion.

He pointed to PJM, which currently prices shortages as high as $6,000/MWh (based on the sum of the shortage pricing and capacity performance settlements). If MISO does not increase its VoLL, Patton said, it will result in inefficient imports and exports with PJM when both markets are tight.

Patton says MISO's proposal fails to address problems with the current curve, which he says overstates the reliability risks for small shortages and understates them for more severe ones. "The steep portion of the ORDC is based on inaccurate loss-of-load estimates" that incorrectly model the loss of only one unit at a time and do not accurately capture wind forecast errors, Patton said.

The Monitor said the curve should reflect the expected VoLL through a calculation of the probability of losing load multiplied by the net value of lost load, resulting in a smoother, more "economic" curve than MISO's current step-based pricing.

FERC Guidance Needed

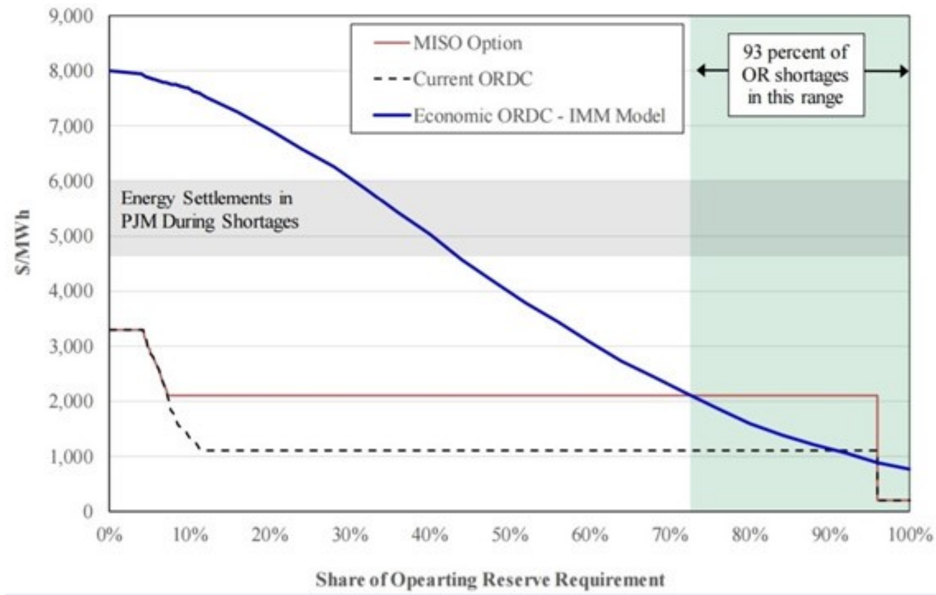
Patton said it would be "helpful" if FERC would offer guidance for creating operating demand curves. "They're set in crude, step-wise curves," he said. An economic curve

Continued on page 14

MISO NEWS

MISO Monitor Recommends Tighter Rules for Constrained Areas

By Amanda Durish Cook



Operating demand curve options | *Potomac Economics*

MISO's Independent Market Monitor is again recommending the RTO expand mitigation measures on narrowly constrained areas by creating a new definition aimed at periods of temporary congestion.

At an April 13 Market Subcommittee meeting, Monitor staffer Michael Wander said the RTO should seek FERC permission to create dynamic narrowly constrained areas (NCAs) to address short-lived congestion and associated market power.

MISO currently has five NCAs with conduct thresholds — prices that indicate potential exercises of market power — that range between $22.31 and $100/MWh. NCAs are defined by FERC as chronically constrained where constraints that can limit competition bind for more than 500 hours annually. They can be defined in advance and are subject to tighter market mitigation thresholds than broad constrained areas.

The Monitor says there are areas that do not meet the 500-hour trigger that also need to be covered by stricter thresholds, as they are "severely constrained areas with one or more pivotal suppliers."

The dynamic NCA would be declared when conduct has occurred that would warrant mitigation on a non-NCA constraint, and that constraint has bound in 15% or more hours over at least five days. The new category, which would set a conduct threshold at $25/MWh, should only be used in "network conditions … that create substantial market power," the Monitor said.

The Monitor first recommended creating dynamic NCAs in its 2012 State of the Market Report.

"We're proposing to move on this as quickly as possible. I think we'll propose Tariff language to stakeholders, and we have affidavits at the ready," Wander said.

To create the category, MISO would have to expand its Module D mitigation provisions in the Tariff. Wander said moving the threshold will not require changes to the RTO's automated mitigation procedures.

Dhiman Chatterjee, MISO director of market evaluation and design, said the RTO is "more or less on the same page" with the Monitor but needs time to review the recommendation.

Had the dynamic NCA definition been in place in 2015 and 2016, it would have been implemented 25 times for an average nine days each, Wander said. The impacts would have ranged from an average of $6.50/MWh to $424/MWh, with the highest price impact at $1,400/MWh. Wander said the simulation showed that dynamic NCAs would have occurred most frequently in MISO's South and Central regions.

MISO, IMM Differ over Scarcity Pricing Changes

Continued from page 13

will reflect the value of reliability and "allow prices to rise efficiently as operating reserve shortages increase."

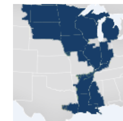
Patton maintains that the current curve's steep jump between $1,100/MWh and $200/MWh results in "volatile pricing" by offline resources that set prices in extended locational marginal pricing. "The shortage pricing under the economic ORDC will track the escalating risk of losing load," Patton said. "In the range where most shortages occur, the economic ORDC is sometimes higher and sometimes lower than the current curve so it should not substantially increase consumer costs for these shortages."

Bladen said there's "almost certainly improvements to be made" to the ORDC, but MISO first must perform its own studies and move the issue through the stakeholder process before it proposes further improvements.

"We've got a lot of things going on right now, but assessing VoLL is not a trivial matter.

Jeff Bladen, MISO

MISO NEWS



Market Subcommittee Briefs

IMM Restates Need for Inter-RTO Constraint Transfer Procedure, Attacks Pseudo-Tie Process


Patton

MISO Independent Market Monitor David Patton on Thursday repeated his call for MISO, PJM and SPP to develop better procedures for transferring control of market-to-market constraints during high congestion.

"It would save all the RTOs a lot of money and improve efficiency," Patton said at an April 13 Market Subcommittee meeting.

Patton pointed to the Feb. 7 transfer of a Midwest constraint to PJM that provided relief for $40 million worth of congestion. (See *Tornadoes, Wind Generation Drive MISO Tx Congestion*.) Market Monitor staffer Michael Wander said PJM still has monitoring control of the constraint in question, and it is not unusual for an RTO to keep control of a transferred constraint for longer periods. "They review it periodically and keep it unless there's a change in the situation," Wander said.

"The fact that PJM physically monitors this constraint doesn't mean that MISO is disadvantaged in any way," Patton told stakeholders.

Northern Indiana Public Service Co.'s Bill SeDoris asked if the Monitor is notified of the transfers.

"Not only are we appraised, we're raising concerns when the transfer hasn't taken place. We tend to be advocates of this," Patton said.

The Monitor reserved his harshest criticism for existing pseudo-tie procedure.

"The only reasonable requirement in our opinion is to get rid of the pseudo-tie requirement into PJM. … The fact that anyone thinks pseudo-tying is a good idea is astounding to me," said Patton, summarizing a Section 206 complaint the Monitor filed against PJM in early April (EL17-62). (See *Pseudo-Tie Feud Rises as Patton, NYISO Protest PJM Proposal*.)

Patton blasted PJM's practice of requiring dispatch control of external generators. "This is an unprecedented requirement," he said. All 12 MISO resources pseudo-tied into PJM were dispatched inefficiently, resulting in 114 new market-to-market constraints in 2015 and 2016, he said.

Patton encouraged stakeholders to file comments in support of his complaint.

Dynegy's Mark Volpe asked if the spike in MISO-PJM pseudo-ties is the result of problems with MISO's capacity market design.

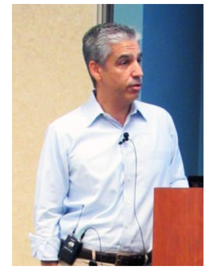
"That certainly can't be ignored," said Patton. "But at this point, MISO's excess capacity is a little higher than PJM's."

MISO: No Resettlements for Tariff Error

MISO will make a Section 205 filing seeking FERC approval for a waiver to void an eight-year-old Tariff mistake that prohibits resources incurring an excessive or deficient energy deployment charges from receiving day-ahead margin assurance payment for multiple hours.

The RTO's Business Practices Manual only bars inefficient resources from receiving day-ahead margin assurance payment for the hour that the charge was incurred. (See *MISO to Fix Recently Discovered Tariff Mistake*.)

The waiver asks FERC to exclude resettlement of previous day-ahead margin assurance payments. The filing will include an affidavit from the Monitor recommending no resettlement.


Bladen

"Resettlements would be extremely damaging to the market and create inefficient financial risk prospectively by undermining market confidence," MISO said.

Bladen said there would be no technology changes to fix the mistake. "Essentially the only cost of this is administrative and legal," he said.

Bladen also said MISO experienced a second-tier maximum generation event on April 4 in MISO South. He said MISO will review the event at the May 11 Market Subcommittee meeting. The Reliability Subcommittee will also review the event.

Expanded ELMP Price-Setting Begins May 1

MISO has filed for FERC approval to expand extended locational marginal price setting to online resources with a one-hour start-up time starting next month (ER17-1081).

The RTO will put the new eligibility into effect on May 1, Bladen said, even without a FERC order of approval. No one has protested the filing.

The new pricing structure preserves the requirement that offline resources must have a start time of 10 minutes or less to set prices. The move will increase the share of peaking resources eligible to set prices from 8% to 58% on a capacity basis, MISO said. (See "MISO to Expand ELMP Price Setting, but not to IMM's Specs," *MISO Market Subcommittee Briefs*.)

— Amanda Durish Cook

MISO NEWS

Resource Adequacy Subcommittee Briefs

Single Year of SPP-MISO Settlement Allocation on Ballot

MISO stakeholders will decide in an email vote whether it's worth debating the cost allocation for holders of firm transmission service reservations of more than 1,000 MW between MISO Midwest and South.

The Load-Serving Entities sector presented a motion to the Resource Adequacy Subcommittee on Wednesday asking that MISO drop the issue, which is an outgrowth of the RTO's settlement over the use of SPP's transmission for North-South transfers. The LSEs said changing the cost allocation of payments to SPP would not provide significant benefits to MISO.

Kevin Murray, representing the Coalition of MISO Customers, asked that a vote on the motion be tabled until FERC acts on the uncontested settlement for cost allocation among MISO members filed in August (ER14-1736, *et al.*), but stakeholders overwhelmingly rejected tabling the motion, 36-2. In the settlement filing, MISO has proposed allocating a declining percentage of the costs to reimburse SPP through a load ratio calculation and an increasing amount through a flow-based benefits methodology.

Keith Berry of the Arkansas Public Service Commission pointed out FERC may not act for quite a while because the commission has been short of a quorum since former Chairman Norman Bay's resignation in February. President Trump has not nominated any replacements to fill the commission's three open seats.

After considerable debate, stakeholders agreed to decide the issue via email. Ballots are due April 19.

Some stakeholders said firm reservations undoubtedly diminished the 2016/17's Planning Resource Auction's transfer capability between the RTO's Midwest and South regions from 1,000 MW to 876 MW, increasing clearing prices.

Last month, some stakeholders questioned whether continuing the debate over the cost allocation was worth the effort. The 1,000-MW-plus usage of the transfer path is only relevant in the 2018/19 planning year, when firm reservations were granted in excess of 1,000 MW. (See "MISO Examines Single Year of MISO-SPP Settlement Allocation," *MISO Resource Adequacy Subcommittee Briefs*.)

Any change would affect no more than 304 MW, because the potential TSRs over the North-South path for the year total 1,304 MW, the LSEs said.

MISO is currently in the fourth year of its settlement agreement with SPP over flows of more than 1,000 MW using SPP transmission to ferry energy between MISO Midwest and MISO South.

MISO Manager of Resource Adequacy Coordination Laura Rauch said the RTO and stakeholders have to reach a decision by November, filing either a cost allocation change or a notice explaining it would not pursue the issue. RASC Chair Chris Plante said the Regional Expansion Criteria and Benefits Working Group could be charged with working out the details if stakeholders decide to pursue a cost allocation change.

Next April, MISO stakeholders will tackle a related issue, deciding if and how to allocate costs to benefiting entities if the RTO raises the amount of capacity that can be transferred between the South and Midwest subregions to more than 1,000 MW in capacity auctions after April 2018.

MISO Still Tweaking OMS-MISO Survey Format

MISO is still tinkering with the format of its annual resource adequacy survey with the Organization of MISO States.

The RTO is proposing a "floating" format in which committed retirements and additions with signed interconnection agreements are left out of the bar graphs and the survey instead focuses on the range of possibilities from planned additions and potential retirements.

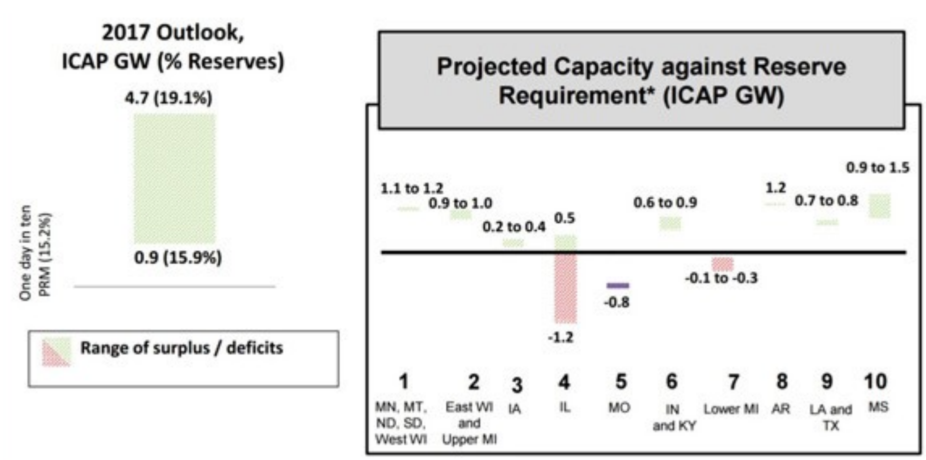
"People tend to gravitate toward the low end of the range. We're really not trying to point people to the low end of the range or the high end of the range," RASC Chair Shawn McFarlane said.

Survey results are expected in June. MISO plans to add a 35% share of projects in the definitive planning phase of the interconnection queue into survey results, although stakeholders have said the completion estimate is too low. (See *Differences Persist over OMS-MISO Survey Improvements*.) Incorporating the 35% calculation would have shifted 2016 results from a possible 15.9 to 17.4% planning reserve margin range to 15.9 to 19.1%. MISO requires a 15.2% reserve margin.

Rauch said MISO will continue to work on the survey format even after results are released in late spring. "We have had it evolve over the years with incremental changes," said Rauch, pointing out that the RTO now focuses on the first five years of survey, rather than the full 10 years. It also shares data for each local resource zone while reporting inter-zonal transfers.

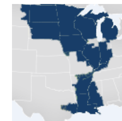
Stakeholders asked if MISO considers other variables, including external resources and wind at full capacity. Rauch said the RTO does consider transfers from other balancing authorities when calculating survey results.

— Amanda Durish Cook



2016 OMS-MISO Survey results with 35% DPP projects in floating format | *MISO*

MISO News



MISO May Bar Units on Extended Outage from Capacity Auctions

By Amanda Durish Cook

MISO is considering prohibiting resources on extended outages from participating in future Planning Resource Auctions or making changes to capture the risk of such outages in loss-of-load-expectation (LOLE) analyses.

Manager of Resource Adequacy John Harmon said MISO wants stakeholder feedback on whether resources on extended outage should be disqualified from PRA participation or if costs of possible outages should be shared by revising modeling assumptions in the annual LOLE study that informs the RTO's planning reserve margin. The changes would not affect PRA 5, the results of which were released Friday. (See story below.)

Harmon told the April 12 Resource Adequacy Subcommittee meeting that MISO's Tariff does not prohibit participation of generators on outage for "significant portions of the planning year." Each year, up to 10 generators providing capacity go offline on outages lasting 90 days to a year, including the summer peak, although the outages are known before the PRA is conducted, Harmon said.

He also said the RTO currently offers an Attachment Y suspension notice for outages longer than 60 days, but use of the form is not mandatory.

MISO recommended stakeholders seek an immediate fix for the 2018/19 planning year and seek a long-term solution afterward.

Harmon asked stakeholders to respond by April 26 with the minimum outage length that should disqualify a resource from PRA participation. Harmon also asked if stakeholders thought generators should be penalized or made to procure replacement capacity if an outage occurs during the planning year. Currently, generators on outages forfeit only their capacity revenue for periods when they are unavailable.

Stakeholders at the meeting asked for evidence to back up the two options.

"I think MISO might be bringing this forward because there's something they see that we don't see," said Consumers Energy's Jeff Beattie. He asked the RTO to bring evidence back to illustrate the possible risk. Beattie said while he did not see a risk posed by extended outages in his Zone 7 for the next three years, "maybe there's something else going on with seasonal outages in other parts of the footprint." Beattie also said there is nothing wrong with dipping into operating reserves to make up for outages.

Ted Leffler of Indianapolis Power and Light asked how often MISO overestimated its seasonal peak in the past and said the RTO should examine both aspects when considering resource adequacy.

Harmon said the problem boils down to the fact that a resource that has completed its generation verification test and identified itself as available during the planning year and then experiences a catastrophic event can still participate in the capacity auction.

"And that's the worst-case example. There's a spectrum of events that could happen," Harmon said.

All Zones at $1.50/MW-day in 5th MISO Capacity Auction

Continued from page 1

tions the region well for reliable operations in the coming year."

Because there were no binding constraints between the zones, all zones' prices were set by an offer submitted by a resource in Zone 1, which encompasses parts of Wisconsin, Minnesota and the Dakotas, Doying said.

The year's "uneventful" results were a function of more supply and less demand, and the lack of constraints. "When you combine those two, you get lower prices and uniform prices. … It doesn't take much to have a significant impact on the clearing results," he said during an April 14 press conference.

Doying also said results weren't surprising given that even a small uptick in supply or a small reduction in demand can drop prices.

Capacity Needs Drop by 730 MW

MISO experienced an overall 730-MW decrease in capacity requirements, resulting from a roughly 1,000-MW decrease in MISO Midwest's requirement and an approximate 300-MW increase in MISO South, indicative of regional economies, Doying said.

At an April 14 stakeholder conference, energy attorney Valerie Green of Michael Best & Friedrich asked if MISO had an explanation for the decline in load. MISO Manager of Resource Adequacy John Harmon said economic slowdowns were consistent across zones that experienced load declines.

Doying said this year's offers included more demand, energy efficiency, solar and wind resources than the 2016/17 planning year auction. Auction results were reviewed and certified by MISO's Market Monitor; no mitigation was required.

The single clearing price is in stark contrast to the RTO's last two PRAs. In the 2016/17 auction, MISO South cleared uniformly at $2.99/MW-day and almost all of MISO Midwest cleared at $72/MW-day, with Zone 1 the lone outlier at $19.72/MW-day. (See *MISO's 4th Capacity Auction Results in Disparity*.) MISO said last year's disparate results were a product of retirements and capacity exports. This year's clearing price also represents a hundred-fold decrease from the $150/MW-day price in Illinois' Zone 4 in the 2015/16 planning year auction.

Illinois Clean Jobs Coalition spokesman Billy Weinberg said the 2017/18 auction results are evidence that market forces are favoring energy efficiency and more affordable renewables. "Now is the time to begin planning for new investments and jobs in Central and Southern Illinois in cleaner technologies like energy efficiency, wind and solar energy that grow cheaper by the day and improve public health," he said.

MISO also said the prices were a result of the improved transfer capability between zones. MISO's South-to-Midwest export constraint increased from 876 MW last year to 1,500 MW this year; the Midwest-to-South limit increased from 2,794 MW to 3,000 MW. (See *MISO to Use Same Sub-Regional Limit Rules for 2017/18 PRA*.)

Continued on page 18

MISO News

All Zones at $1.50/MW-day in 5th MISO Capacity Auction

Continued from page 17

This year, the RTO's maximum offer using the cost of new entry ranged from $246/MW-day for Zone 10 in Mississippi to $265/MW-day for Zone 5 in eastern Missouri.

In March, MISO predicted that all local resource zones would have enough capacity to meet their individual clearing requirements, with 172 GW worth of total installed capacity easily meeting the RTO's 135-GW planning reserve margin requirement. (See "Preliminary PRA Data Show Capacity Excess," MISO Resource Adequacy Subcommittee Briefs.)

Harmon said auction results will be presented to stakeholders in a more detailed presentation at the May 10 Resource Adequacy Subcommittee meeting.

In a research note Friday, UBS Securities analysts Julien Dumoulin-Smith and Jerimiah Booream called the results "a material disappointment for MISO, sending prices back to their historic lows of 2012 and 2013. … This will prove difficult to shift out of given the impacts from [the Mercury and Air Toxics Standards] and other environmental regulations that drove the improvements in prior periods."

UBS had predicted prices would clear no lower than $12/MW-day. The analysts said prices would have been closer to $10/MW-day based on the lower demand but that the offer curve was also "flatter" because of Illinois' approval of zero-emission credits for Exelon's Clinton nuclear plant, which left the company less concerned with maximizing its capacity revenue. "This was the decisive factor in holding prices lower," they wrote.

Same Auction Process

The auction was unchanged from its usual format, despite MISO's attempt at a redesign that would have bifurcated the capacity market by holding a forward auction for competitive load three years prior to the prompt PRA. In February, MISO abandoned the changes after a curt FERC rejection. (See MISO Won't Seek Rehearing on Auction Redesign.)

Doying said MISO has "other priorities" than reviving the Competitive Retail Solution. He said the RTO will continue a discussion about resource adequacy in Michigan and Illinois.

Exelon's decision to keep its Quad Cities nuclear plant operating — thanks to Illinois' approval of zero-emission credits to provide the plant additional revenue — has eased some of MISO's concern, Doying said.

External Zones, Seasonal Classification

That does not mean MISO is dropping plans to improve the PRA. While a possible two-season classification is on ice for the remainder of 2017, the RTO is currently navigating the stakeholder process on creating external capacity pricing zones.

"Industry forces continue to indicate significant shifts in the fleet," Doying said. "MISO will continue to address seasonal and locational issues with our stakeholders while ensuring that market signals provide incentives for investment where and when they are needed."

At an April 12 RASC meeting, MISO's Laura Rauch asked stakeholders how different classes of external resources should be treated. She presented stakeholders with examples of pseudo-tied resources, border resources and coordinating owners such as Manitoba Hydro. She also asked about contracts signed before the formation of the MISO market in 1998 or FERC's 2012 approval of the PRA construct.

"What is the best method to recognize the contracts of existing resources?" Rauch asked stakeholders.

MISO is also asking stakeholders what rules should dictate external zone pricing. The RTO has proposed that the external zone price be based on the sink of the external resource.

Last month, the Monitor suggested pricing be based on balancing authority boundaries, with resources connected to both sides of Midwest-North constraint receiving a blended price. (See "IMM Offers Own PRA External Zone Design," MISO Resource Adequacy Subcommittee Briefs.) Rauch said MISO will use stakeholder input to draft Tariff language and address the Monitor's proposal at the May RASC meeting. Rauch said MISO staff is still evaluating the proposal.

Illinois Municipal Electric Agency's Rakesh Kothakapu said MISO needed to be careful with pricing, especially considering external zones continue to be priced low while supply continues to tighten. "We don't want to end up in a situation where we price them lower even when it has nothing to do with a constraint," he said.

A seasonal auction classification is beginning to look less certain.

"There's a general thought that stakeholders aren't as interested in a seasonal construct as they once were. The informal feedback I'm receiving is along those lines," RASC Chair Chris Plante said.

In January, some stakeholders said the seasonality proposal had fallen out of favor after MISO revealed design specifics last year. (See MISO Plans Additional Capacity Auction Revamps for 2017.)

NYISO News

NYISO Provides Update on Response to Capacity Export Concerns

By Michael Kuser

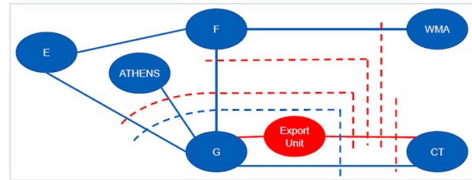
RENSSELAER, N.Y. — NYISO updated stakeholders last week on its response to concerns over capacity exports, providing a status report on modeling revisions and recommending stakeholders consider broad policy changes as part of the ISO's 2018 Project Prioritization Process.

The ISO is attempting to insulate consumers from anticipated capacity price spikes in the Lower Hudson Valley and New York City zones expected as a result of FERC's October order allowing the 1,242-MW dual-fuel Roseton 1 generator to export some of its capacity to ISO-NE. The plant, 43 miles north of New York City, is in the import-constrained G-J locality.

In January, FERC approved NYISO's plan to change its capacity market rules to recognize the impact of counterflows. The new rules use a "locality exchange factor" to reflect how much capacity from "rest of state" can replace capacity exported from an import-constrained locality. The prior rules assumed that 100% of a generator's exports from an import-constrained area must be replaced with generation in that locality.

In February, the ISO submitted a compliance filing eliminating a one-year transition rejected by FERC (ER17-446). (See *FERC OKs NYISO Capacity Revision; Rejects Transition Plan*.)

ISO officials now are working with General Electric to develop a probabilistic approach to determining the locality exchange factor. The new methodology could replace the deterministic method designed last year and approved by FERC.



Reserve sharing topology | *General Electric*

Emilie Nelson, vice president of market operations, told the April 12 Business Issues Committee meeting that "the subject is proving more complicated than expected."

GE presented its proposed methodology and export topologies at the March 22 meeting of the Installed Capacity Working Group. It is expected to present preliminary results of its analysis at the working group's April 19 meeting.

By June 1, the ISO plans to file an informational report with FERC outlining work that will remain to be done after that date.

NYISO recommended stakeholders consider the topics of capacity imports, payments to capacity-exporting generators and capacity resource interconnection service in the 2018 Project Prioritization Process, which allows stakeholders and the ISO to rank proposed initiatives against one another based on expected benefits and costs. The initial list of project candidates and descriptions will be on the agenda at the Budget & Priorities Working Group meeting April 26.

NYISO NEWS

Gas, LMPs Rebound in NY, New England in March

Continued from page 12

Henry Hub gas prices, but there are reasons to be bullish on Northeast prices, with the region facing coal retirement and capacity issues."

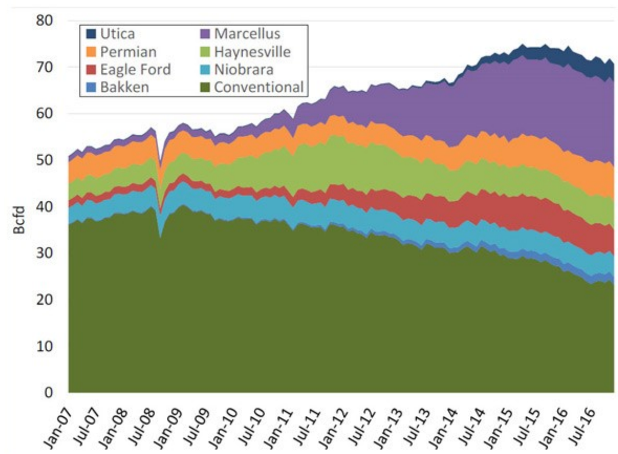
The Iroquois pipeline delivers natural gas to western Connecticut from the Canada-New York border southeast of Ottowa, while the Algonquin pipeline carries Marcellus shale gas from Pennsylvania into Connecticut and Massachusetts. "Right now the market is rallying on that, and bullish on Marcellus translates into bullish downstream of Marcellus," Grimes said.

About 1.0 Bcfd of new FERC jurisdictional pipeline capacity went into service last year in the Northeast, including the Transco Rock Springs expansion (192 MMcfd), the First ECA Midstream project (152 MMcfd) and the Algonquin Incremental Market Project (342 MMcfd), which began operation in the fall.

FERC State of the Markets Report

The March price spikes came following a year that brought record-low natural gas prices and near-record-low power prices, FERC reported in its 2016 State of the Markets report, released Thursday. (See related story, *FERC: Gas Continued to Dominate in 2016*, p.32.)

"Although natural gas production fell for the first time since 2005, flat demand due to above average winter temperatures at the start of the year and high natural gas storage inventories contributed to the low prices," FERC said. "The low natural gas prices further incentivized gas-fired generation in 2016, and for the first time in history, natural gas' share of total electricity generation output overtook coal's on an annual basis."



Natural gas production | *FERC/EIA*

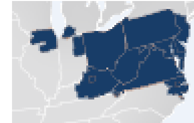
Henry Hub prices averaged $2.48/MMBtu, the lowest level in 20 years, FERC reported.

"Above average temperatures in the 2015-2016 winter limited natural gas demand during the first three months of the year, leading to robust storage inventories at the start of the 2016 injection season in April, and reduced demand for storage injections through the summer. Prices fell to record lows in the first half of 2016, before climbing thorough the second half of the year driven by steady domestic demand, rising exports and a drop in production."

Although the highest in the country, gas prices in Boston were down one-third from 2015. New York City prices showed the largest decrease from 2015, dropping 42%.

U.S. gas production fell 2.5% to 72.3 Bcfd, the first annual drop since the burst in shale production began in 2005.

PJM News



New FTR Task Force on the Way for PJM?

By Rory D. Sweeney

VALLEY FORGE, Pa. — With several changes under consideration for its financial transmission rights processes, could PJM be forming another FTR task force?

PJM convened task forces in 2011 and again in 2015 to address FTR underfunding.

At Wednesday's Market Implementation Committee meeting, Direct Energy's Jeff Whitehead presented a proposed problem statement and issue charge to address the allocation of day-ahead surplus congestion funds and FTR auction revenue surplus funds.

Other stakeholders immediately questioned the proposed language, concerned that it seemed to "presuppose" a solution. Whitehead and other sponsors of the problem statement, including Steve Lieberman of American Municipal Power and John Rohrbach of ACES, representing the Southern Maryland Electric Cooperative, agreed to revise it.

PJM's Asanga Perera supported the proposal, saying the RTO attempted to implement it but was told by FERC it should go through the stakeholder process. Independent Market Monitor Joe Bowring favored it as well.

Barry Trayers of Citigroup Energy felt it remained too narrowly focused. "There's a lot of moving parts and this misses a ton of them," he said.

Whitehead defended the initiative, saying FERC narrowed the scope with its September order directing PJM to allocate balancing congestion costs to real-time load. By removing a major source of FTR underfunding, he said, the existing funding sources can be reviewed and removed if unnecessary. (See *FERC Finds PJM ARR/FTR Market Design Flawed; Rejects Proposed Fix*.)

"But I guess we're going to talk about that in the FTR task force," Whitehead said.

His issue charge does not call for creating a task force — instead suggesting the issue be addressed by the MIC.

But there are other FTR issues pending as well. Later in the meeting, Perera discussed several other FTR updates, including additional information on the delayed results for the March 2017 FTR auction. He said he asked other RTOs about their processes.

"They all said PJM's process is extremely complicated," he said. "None of them have any overlapping periods like we do."

Perera proposed removing the single quarterly auction that overlaps monthly auctions or developing software upgrades to speed up the solution time. (See "FTR Lateness Blamed on High-Volume Period," *PJM Market Implementation Committee Briefs*.)

"Hardware, software, market structure — there are things that can be done better than the one-off solution of killing one quarter," DC Energy's Bruce Bleiweis said.

"The IMM supports PJM's proposal to remove the overlapping-period quarterly auction as a solution to the issue, at least as a stop-gap measure. The monthly component product periods of the quarter will still be available and market-sensitive auction results will be made available on a more timely basis," said Howard Haas, the Monitor's chief economist.

Another Wrinkle Delays Spot-in Changes for PJM

By Rory D. Sweeney

VALLEY FORGE, Pa. — After years of dragging the issue forward, Vitol's Joe Wadsworth was about to see PJM stakeholders vote on schedule changes to accommodate spot-in sales between the RTO and NYISO.

But the scheduled vote at Wednesday's Market Implementation Committee meeting was delayed after John Rohrbach of ACES said PJM's simple solution for solving the problem would harm power sales in the South.

PJM had proposed delaying the spot-in request time by an hour to 10 a.m. across all seams, which would allow market participants looking to bring in power from NYISO the time to confirm they were approved by the ISO to export power. However, the delay causes issues along PJM's southern border, Rohrbach argued.

Rohrbach said that the daily sales market in southern states begins early in the morning and is generally done by 10 a.m., so any power that doesn't receive approval for PJM spot-in service wouldn't have another market to be sold in. At 9 a.m., however, opportunities still exist to make bilateral trades, he said.

"Today, if you don't get spot-in, you have other opportunities," he said. "By 9, it's already starting to tail off. … If you wanted to change the time to 8 a.m., we'd actually be happier with that."

The South is a thinly traded market and the vertically integrated utilities there are comfortable with their schedule, Rohrbach said. They are "guaranteed" not to conform with PJM's proposed changes, he added.

The news wasn't bad for Wadsworth, who had originally proposed a more complicated, market-based solution and later suggested that the time change be limited just to the NYISO seam, which was opposed by the Independent Market Monitor. NYISO had also proposed a market-based solution that PJM stakeholders rejected. (See "Vitol Accepts Simplified Solution to Spot-In Issues," *PJM Market Implementation Committee Briefs*.)

"We are happy to compete in a competitive marketplace. … I was very clear that I didn't want to make a change that would impact others," Wadsworth said. "This kind of creates the balloon effect — squeeze the balloon at one place and it's going to pop out at another."

PJM's Chris Pacella said the issue with the market-based proposals are that they will require software upgrades, which would take time and resources. Stakeholders acknowledged the challenges but urged Pacella to see if the proposal could be accommodated using the current system.

"I know it's not your preference, but you should at least look at adjusting [PJM's software] to try the NYISO solution without hurting the other seams," Direct Energy's Jeff Whitehead said.

"I certainly feel for the folks who are trying to solve this," said Carl Johnson of the PJM Public Power Coalition. "We took on the problems serially. We haven't invested our best problem solving techniques. I don't think we've given this our best effort."

Throughout the spot-in discussion, the Market Monitor has insisted on maintaining consistent rules across all seams, which Monitor Joe Bowring highlighted ironically by quoting Ralph Waldo Emerson: "'Consistency is the hobgoblin of small minds.'" He supported considering Rohrbach's concerns and leaving the current rules in place in the interim.

Wadsworth agreed to remove his request for a vote on the proposal, but he asked stakeholders to help him revise the problem statement. Rohrbach immediately volunteered.

PJM NEWS

PJM Utilities Ask to be Kept in Loop on DER Installations

By Rory D. Sweeney

"We simply need to know what's happening before it happens and not after the fact. That will give us the opportunity to determine what needs to be done."

Bruce Remmel, FirstEnergy

VALLEY FORGE, Pa. — PJM invited two distributed energy resource developers to explain their operations and presented a case study of its own at a special session of the Market Implementation Committee on April 10. The presentations elicited concern from electric distribution companies, who asked that rules be implemented that keep them informed when customers want to install such systems.

"We simply need to know what's happening before it happens and not after the fact. That will give us the opportunity to determine what needs to be done," FirstEnergy's Bruce Remmel said.

Calpine's David "Scarp" Scarpignato said stakeholders could benefit from EDCs providing information to PJM on such interconnections. "A lot of small [projects] can add up to big numbers," he said. "It seems to me like the notification should go two ways."

PJM discussed a recent visit by staff members to Hopewell Valley Central High School in Pennington, N.J., where Public Service Electric and Gas has installed a solar and battery system. The 580-kWh Hopewell battery is an "in front of the meter" system but doesn't qualify as an "energy storage resource," PJM staff said, because it is primarily a backup power system for the school during an outage and therefore doesn't fit the definition of a storage resource. Instead, it's accounted for under "station power" rules, even though it provides regulation, capacity and energy services to the RTO.

Hopewell Valley Central High School | *PJM*

PJM's Andrew Levitt, who led the presentation, explained that a resource can be designated either in front of the meter — meaning it's able to provide capacity and energy services — or behind the meter, meaning it can be used to net against load for wholesale transmission, capacity and ancillary services charges. The same megawatts cannot be used for both simultaneously, he said.

Drew Adams of A.F. Mensah and Adesh Harripersad of Distributed Asset Solutions highlighted how their businesses have handled installations of both types of resources in PJM.

It was A.F. Mensah's problem statement and issue charge that precipitated development of the special sessions, borne out of the challenges faced with PJM's policies on how systems combining batteries and renewables must be interconnected. (See *PJM Considering Injection Rights for Demand Response*.)

The company has moved forward with projects using the existing rules while they're being discussed in this stakeholder process.

Adams highlighted some of the challenges and experiences when complying with all existing rules. Adams said his company paid a $500 application fee for each of 20 installations and that the installations are aggregated in PJM's models as a single 0.1-MW market resource. He presented diagrams showing how the projects require two separate electric service lines to an end customer site: one for the existing service line including behind-the-meter solar panels, and a new service line for the battery storage system so its capabilities can be sold directly into PJM. The battery system acts independent of the customer load and solar in normal operation and is then connected to the load and solar through redundant switch gear during a bulk grid outage.

He explained that the systems have five meters, each providing different information to different recipients. FirstEnergy's Ed Stein said that creates concerns because partial information may make it impossible to fully understand what's going on with a system.

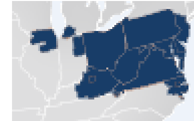
"Ultimately, I think there will be a lot more information sharing between EDCs, transmission owners [and] PJM," Stein said. "We're going to have to come up with an information-sharing paradigm that works for everybody. We may find ourselves that not one single entity has all of the information or ownership of all information at its disposal to give. … We've got a lot to consider with information here: who's going to have it, who's going to provide it, who's going to be able to see it and access it and understand it."

Adams said his company is supportive of those discussions.

Harripersad discussed the coordination issues that make project development and construction difficult. He works with funding provided by True Green Capital Management to develop photovoltaic solar arrays throughout the country. Even with long lead times — with delays created by the need to secure everything from state environmental approvals to local construction permits — projects are often a rush at the end, he said.

"All these things add up to, literally, down to the wire; you have three months to build everything," he said. "The big thing is getting our projects interconnected."

PJM NEWS



OC Briefs

Inconsistent Weather Contributes to Operational Inaccuracies

VALLEY FORGE, Pa. — Power demand proved difficult for PJM operators to forecast in March as a snowstorm was followed by exceptionally warm weather, RTO staff told participants at last week's Operating Committee meeting.

"That was the story of March: a lot of up and down," PJM's Chris Pilong said.

The balancing authority area control error limit (BAAL) performance score dipped to 99.4%, the lowest it's been since last March, PJM's Ken Seiler said, with 257 excursion minutes. The BAAL was high in some cases, suggesting that plants were over-generating, he said. The longest excursion lasted nine minutes.

"This is eerily similar to what we had last year," he said.

A 24-minute spinning event on March 23 occurred when market-to-market constraints in MISO prevented PJM from loading combustion turbines from the west, as the RTO had planned, Pilong said. PJM is looking at the event to determine which units responded and which did not, Seiler said.

Calpine's David "Scarp" Scarpignato, with PJM's Adam Keech in the background. | © *RTO Insider*

PJM's perfect dispatch performance is 76%, which is about six percentage points lower than it was at this time last year.

PJM Wants to Study Frequency Response

PJM is proposing a problem statement and issue charge to understand why many generating units either aren't providing frequency response or are responding incorrectly to signals from the RTO.

While frequency response is essential for grid reliability, a 2012 NERC report found that only 30% of units were providing primary frequency response, PJM's David Schweizer said. FERC published a Notice of Proposed Rulemaking on the topic in November that would require all new units, excluding nuclear, to provide the service. The commission is considering the comments it received. (See *FERC Seeking Comments on Primary Frequency Response*.)

In a survey of its generators last year, PJM found that, among its critical load resources — generators with a four-hour or less hot start time — just 95% have a functional governor, 75% are using NERC-recommended settings and 25% are using controls that override frequency response.

Other grid operators, including CAISO, MISO and ISO-NE, have requirements consistent with NERC reliability standards, PJM said.

The new rules, which PJM would be looking to implement for all units, would comply with NERC standards and might also include compensation, even though the NOPR didn't propose that.

PJM had suggested separating the components across the Operating and Market Implementation committees, but stakeholders were adamant that they should be kept together to ensure any market signals are designed to incent the desired behavior.

A PAR Too Far?

PJM and NYISO are still interested in replacing a broken phase angle regulator at Consolidated Edison's Ramapo substation, despite stakeholder skepticism about its necessity. The grid operators are holding a meeting today at NYISO's offices to discuss the situation and consider modifying their

Continued on page 24

MIC Briefs

Shortage Rule Takes Effect amid FERC Silence

VALLEY FORGE, Pa. — FERC did not act on PJM's proposed changes to its shortage pricing, so revisions for how to handle transient shortages will go into effect May 11 as planned, Manager of Real-time Market Operations Lisa Morelli told the Market Implementation Committee on Thursday. (See "Order 825 Implementation Moves Forward," *PJM Market Implementation Committee Briefs*.)

The curve step changes are still on track to be implemented on July 1, but it's unclear whether that will definitely happen.

"There's unfortunately uncertainty [about] a lot of what's happening at FERC right now," PJM attorney Steve Shparber said. "We will keep going on until we hear otherwise."

PJM's plan would change the scarcity signal for the maximum $850 penalty factor from the economic maximum of the single largest contingency to the highest actual output of a single unit. Next, it would add two lower "steps" that would trip a $300 pricing level. One step would be calculated as the highest actual output plus 190 MW — a static number derived from the synchronous reserve mean of the Mid-Atlantic Dominion zone plus one standard deviation. The second step would be calculated as the previous step plus an extension.

PJM to Review Black Start Prior to New RFP

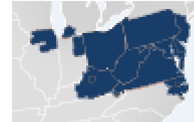
PJM released its first request for proposals on black start units in 2013 to have them in place by 2015. As part of that process, the RTO instituted a five-year review, meaning the next black start RFP will be in 2018 for project to be available in 2020.

To begin that process, staff will be holding a special one-hour session after the May 2 Operating Committee meeting to review results and lessons from the first RFP. Stakeholders pointed out that that is the second day of the FERC technical conference on the impact of state policies on RTO operations in PJM, ISO-NE and NYISO (AD17-11). PJM staff promised the meeting will be quick.

Earlier in the meeting, stakeholder endorsed changes to the annual revenue requirements for black start units. PJM and its Independent Market Monitor came to an agreement on having the revenue go into a non-interest-bearing account for each unit until its costs have been approved, at which point the RTO will conduct a true-up.

— Rory D. Sweeney

PJM News



PC/TEAC Briefs

Give Me the Bad News First … PJM Wants Comments on Competitive Tx Manual Revisions

VALLEY FORGE, Pa. — Stakeholders quickly approved administrative revisions to Manual 14B at last week's Planning Committee meeting, but gaining endorsement for the newly developed Manual 14F is likely to be a more complex task.

The new manual will cover the competitive planning process. PJM, which has been updating the proposed language based on stakeholder feedback, asked members to submit any additional comments now so the manual will be up to date when it's approved. The RTO called attention to its "decisional process diagram" (section 8, attachment 4). (See PJM Making Cost Consciousness a Focus for RTEP Redesign.)

"We really would like to get the comments now so we can integrate them," said Steve Herling, vice president of planning.

Sharon Segner of LS Power questioned why provisions for cost containment aren't thoroughly outlined and asked for a full vetting of the proposed text because there have been so many revisions.

PJM will bring the manual to the Markets and Reliability Committee on April 27 for a first read and hopes to receive endorsement in May.

Should I Stay or Should I Go? PJM Still Searching for Resolution to Interconnection Queue Issues

When PJM changed its interconnection queue processes several years ago, the purpose was to ensure everyone paid their fair share of infrastructure upgrades. Previously, whichever project triggered an upgrade would be on the hook for it, no

PJM's Mark Sims (left) and Dave Egan | © *RTO Insider*

matter how much it contributed to the problem. By having all projects wait in a six-month queue under the new rules, every request that contributed to an upgrade could contribute to paying for it.

"It seemed like a great idea that everybody would take a small piece of a $5 million impact," said PJM's Aaron Berner, who is leading the review of the interconnection process. "We haven't come up with a way to

Continued on page 25

OC Briefs

Continued from page 23

joint operating agreement. The joint stakeholder interactions are intended to create criteria for a benefits analysis that would factor in the cost allocation of any remedies. (See PAR Wars: A Struggle for Power.)

PJM's Stan Williams walked through a presentation NYISO created on the issue, in which the ISO urges replacing the PAR.

"They see enough benefit there that they want to move ahead with replacing the second PAR by the fall," he said.

Williams said the joint stakeholder engagement will be beneficial as it might create a roadmap for future cross-border projects. PJM uses a similar benefits analysis with MISO in determining transmission, he said. Gabel Associates' Mike Borgatti asked PJM to develop a presentation on how that process works.

Carl Johnson of the PJM Public Power Coalition and Calpine's David "Scarp" Scarpignato complained about the PAR meeting being scheduled on one of PJM's only two no-meeting days of the month. Both said they will be unable to attend.

"You're going to have a one-sided meeting. It only happens once a month," Scarp said.

Dave Pratzon of the GT Power Group supported PJM's engagement with NYISO on the issue, pointing out that the RTO objected when MISO attempted to make PJM pay for PARs installed on the Michigan-Ontario border.

PJM Seeking Feedback on Fuel-Security Report

Vice President of Operations Mike Bryson walked through a paper PJM released last month on fuel security in the RTO and asked for stakeholder feedback. (See PJM: Increased Gas Won't Hurt Reliability, Too Much Solar Will.)

Although the paper found a capacity mix of more than 20% solar would threaten reliability, Bryson noted that currently renewables only make up about 2% of the mix.

The paper was very narrowly focused, he noted, and purposefully didn't address other topics, such as environmental issues or whether natural gas infrastructure could keep pace with the high percentage of gas-fired generators PJM's analysis said the fleet could handle. The paper did not identify a percentage of gas-fired units that would threaten reliability.

Additionally, it didn't consider dual-fuel units or units with access to multiple fuel pipelines. It also assumed that all units had confirmed supply contracts.

FirstEnergy's Jon Schneider pointed out that the study highlighted only a third of the portfolios that PJM considered "desirable" would be resilient enough to withstand polar vortex-type conditions, which the study attributed to "the increased risk of natural gas delivery under extremely cold and high load conditions." He asked for clarity on assumptions made regarding gas supply, as it can be either firm or interruptible.

Bryson acknowledged that the study assumed firm service for all units and said that the results would factor into PJM's planning going forward.

Scarp said many gas units have access to multiple pipeline sources and that, despite coal units maintaining a 30-day onsite fuel supply, many such piles were frozen and unusable during the 2014 polar vortex and recalled a similar period in 1994 that resulted in rolling blackouts.

"Just because you have a 30-day inventory doesn't mean you have supply for 30 days," he said.

— Rory D. Sweeney

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fix it without switching back" to the earlier cost allocation process.

At issue is how to fairly allocate upgrade costs without unreasonably delaying project completions. Back when most projects were large-scale plants with long construction lead times, PJM instituted a rule that all projects would be held in a six-month queue to determine if any upgrades would be necessary for the requests in the queue. Upgrade costs that totaled less than $5 million were allocated to all projects upon the queue's closure.

Because projects can be much smaller and completed much faster now, the six-month wait time can delay developers' schedules. PJM is proposing a rule change that would allocate costs of upgrades to the first request that necessitates the spending. Any subsequent requests in the queue would contribute proportionally. (See *PJM Considering Injection Rights for Demand Response*.)

Returning to this "first to cause" strategy for upgrades less than $5 million has largely gone unchallenged by stakeholders in a series of discussions on the topic, which caused Carl Johnson, who represents the PJM Public Power Coalition, to question who among the stakeholders would be disadvantaged by the change back. He pointed out that there will be an unlucky project that receives the cost allocation.

"I'm curious how that will play out," he said.

"That's another incentive to coming in [to the request queue] early," Berner said.

The Tariff and manual changes are on track to be implemented for the project queue that opens on Oct. 1, he said.

NYISO Changes Spur PJM Review of Emergency Import Abilities

With the termination of the decades-old wheeling service through North Jersey and the near-term retirement of the Indian Point Nuclear Station, PJM is reviewing its ability to import power during an emergency.

PJM's Mark Sims said the study of its capacity emergency transfer objective (CETO) and capacity emergency transfer limit (CETL) tests assumes a locational deliverability area (LDA) is at a 90/10 load level and in a generation-capacity emergency — in other words when the "load is high and they're having issues with generation," Sims said.

To ensure the system has adequate deliverability, the CETL must be equal to or greater than the CETO. Those numbers are calculated through thermal and voltage analyses. Facilities whose outage transfer distribution factors (OTDF) are more than 5% are considered in violation, as are factors more than zero on transmission lines that are 345 kV or larger. The OTDF measures how power transfers using the infrastructure being studied impact the system during an outage.

"We need to take our objective and turn it into a simulation," Sims said. "During [an] actual emergency, operators are going to do what they can do to keep the lights on. That's what we're trying to reflect."

Solar Forecast is Coming

Mulhern

PJM is developing a solar forecast and will need to make several Tariff and manual changes to accommodate it, said Joe Mulhern, senior engineer and project manager. The move — mandated by FERC Order 764 — comes as PJM has seen solar installations take off, from virtually nothing in 2007 to approximately 1,000 MW today.

"It's really just so we're ahead of the curve on solar installation," Mulhern said.

The aggregate forecast data will be available to members for operational planning, transmission outage coordination and generation offering and scheduling. The project is targeting implementation by the end of the year. It would only apply to front-of-the-meter solar generators.

The rule changes would also require real and reactive power telemetry for solar generators of 3 MW or greater. At the Operating Committee meeting last week, American Electric Power's Brock Ondayko asked why such plants would also be required to report temperatures from the backside of solar panels.

"If you want it, we'll give it to you," Ondayko said. "I don't know if the information is going to be accurate or not. … It seems to me just because things could be available, I think PJM should have to think of why it's necessary."

Staff: Developers Have no Right to Retain Previously Proposed Projects

Transmission developers whose proposals don't get approved will need to continue proposing them until the constraint disappears or risk another developer landing the project if it ever is approved, PJM staff told participants at the Transmission Expansion Advisory Committee meeting.

One stakeholder, who declined to be quoted by name, asked about a "right of first refusal" policy, noting that he noticed several new proposals that had appeared to be the same as previous proposals.

"It seems kind of unfair" that a company could have proposed a project that was rejected, only to see a "copycat" receive approval for it later, he said.

PJM's Herling said the idea was discussed at FERC when the competitive transmission rules were being developed, and the commission specifically ruled out such a provision.

"The bottom line is we start over every time," Herling said. "You have to propose in every window if there's congestion to be addressed."

"Lesson learned," the stakeholder replied.

— Rory D. Sweeney

"It seems to me just because things could be available, I think PJM should have to think of why it's necessary."

Brock Ondayko, AEP

SPP NEWS

SPP Z2 Panel Sees ILTCRs as Cure to 'Mess of Complexity'

By Tom Kleckner

TULSA, Okla. — SPP's Z2 Task Force last week conducted a series of votes to determine potential alternatives to the RTO's cumbersome crediting system for transmission upgrades in time for a July deadline.

The group's consensus is that incremental long-term congestion rights (ILTCRs) modeled after the RTO's LTCR process and some modifications to the Z2 process are the best options for moving forward.

"We're separating the must-haves from the nice-to-haves," Kansas City Power & Light's Denise Buffington, the task force's chair, told the Markets and Operations Policy Committee on April 12.

Under Attachment Z2 of the RTO's Tariff, members are assigned financial credits and obligations for sponsored upgrades. The task force is trying to simplify the process — which resulted in eight years of incorrectly applied credits — while still meeting FERC requirements.

It hasn't been easy.

"It's a mess of complexity," SPP's Charles Locke said, referring to three different funding mechanisms for the Z2 process: base plan, directly assigned costs and point-to-point clawbacks under various Tariff schedules.

"I'm not interested in coming to another meeting with more data and more proposals, and [having] another discussion on why we don't like the process," Buffington said, keeping the group on task during its meeting before the MOPC session.

From left to right: Richard Ross (AEP), Bruce Rew (SPP) and Denise Buffington (KCP&L) | © *RTO Insider*

After "spirited discussion," as Buffington described it to the MOPC, the task force approved:

- Replacing the existing Z2 process with ILTCRs for all three upgrade types (sponsored, transmission service and generator interconnections). Doing so would require a secondary market to trade the ILTCRs and make them fully transferable, following examples set by MISO, PJM and other RTOs. Staff proposed using a modified ILTCR process for generator interconnection upgrades and the existing process for the other two upgrades but said it would need further study and software changes costing hundreds of thousands to implement all three categories.
- A rate allocation similar to the Tariff's schedules 11 and 13 for all three categories, with a limited roll-in of the facilities' cost, depending on the extent to which it is used for subsequent transmission service. The proposal is focused on compensating service-upgrade sponsors, but it could be used for the other two categories.
- Consideration of a standard credit payment rate that would put point-to-point payment obligations on par with network obligations.
- Eliminating credits for short-term transmission service by decoupling a short-term transfer tool from the credit stacking system. Short-term impacts will no longer be "stacked" to determine when a creditable upgrade becomes reverse creditable. Staff assumes "fairly minimal" changes with this option and said it could take as little as two months to implement.
- Eliminating credits for non-capacity upgrades.

The task force has scheduled two additional meetings to make a final decision and put together a final recommendation for the MOPC and Board of Directors meetings in July.

SPP Adds 95th Member in Wholesaler Southern Power

TULSA, Okla. — SPP has increased its membership roster to 95 with the addition of Southern Power, the wholesale arm of utility giant Southern Co.

COO Carl Monroe made the announcement Wednesday during SPP's quarterly Markets and Operations Policy Committee meeting. Southern Power's membership was effective April 11.

Southern Power "is excited to join the Southwest Power Pool as a member and looks forward to collaborating with our fellow stakeholders to help shape the future of energy," Jim Howell, Southern Power's transmission and regulatory policy manager, said in a statement.

"We thank you for your contributions to the administrative fee," cracked MOPC Chair Paul Malone, with the Nebraska Public Power District, addressing a company representative at the meeting.

Southern Power owns four wind farms in SPP's footprint, three in Oklahoma (totaling 597 MW of capacity) and the 276-MW Bethel Wind Facility in the Texas Panhandle.

The company's portfolio includes 46 natural gas, wind, solar and biomass generating assets spanning all four time zones.

— Tom Kleckner

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SPP, Mountain West in Agreement over Allocating Existing Facilities

TULSA, Okla. — SPP COO Carl Monroe told the Markets and Operations Policy Committee last week that allocating costs for existing transmission facilities would not be an issue should the Mountain West Transmission Group be successful in its quest for RTO membership.

Mountain West doesn't expect to pay for SPP's facilities "past or present," Monroe said, and SPP is "thinking similarly."

"We have a current situation within SPP where we're not sharing costs of the upgrades across the Eastern and Western Interconnections," he said. "There's already a situation in the SPP Tariff that, through contract, load in the West doesn't pay for Eastern upgrades. That makes sense, because they don't get any electric benefits out of that."

SPP and Mountain West are also trying to determine whether to operate as a single market or two separate markets. There are currently four DC ties between SPP and Mountain West facilities, with a total capacity of 710 MW. Mountain West's membership would place all seven U.S. ties between the Eastern and Western Interconnections under SPP's Tariff.

"We're talking with vendors, technical staff and outside experts to see whether it's possible to operate a market over DC ties," Monroe said.

Monroe was unable to answer several questions from members, citing confidentiality issues. However, he welcomed stakeholders to participate in the Strategic Planning Committee's executive sessions, where discussions on Mountain West's potential membership will take place. (Members will have to sign non-disclosure agreements to participate.)

Monroe and Tri-State Generation and Transmission Association's Mary Ann Zehr said Mountain West hopes to determine whether to continue pursuing membership before July. The two entities would begin drafting revisions to governing documents shortly thereafter, with the intention of getting SPP board signoff in January 2018.

SPP and Mountain West officials both participated in an informational forum before the Colorado Public Utilities Commission on March 28. (See *Mountain West, SPP Tout RTO Membership to Colo. PUC*.)

The MOPC meets in Tulsa on April 12. | *© RTO Insider*

Members OK Removing SPS Line from 2017 ITP10

The MOPC overwhelmingly agreed with staff's recommendation to remove a Southwestern Public Service 345-kV line from the 2017 Integrated Transmission Planning's 10-year assessment. The vote was opposed only by independent transmission companies ITC Holdings and Hunt Transmission, with Golden Spread Electric Cooperative and South Central MCN abstaining.

The MOPC and SPP's board directed staff in January to further evaluate the Texas Panhandle project following pushback from SPS, which said it was "the wrong time" for the line. (See "Board Sends $144M Tx Project Back for Re-evaluation," *SPP Board of Directors/Members Committee Briefs*.)

Staff's further evaluation and modeling changes revealed a 6.5% decrease in the SPP region's adjusted production costs savings, and a third-party review using more detailed routing assumptions lengthened the project from 90 miles to 109 and increased the $144 million cost estimate to $173 million.

In March, SPS parent Xcel Energy announced it would add 1,230 MW of new wind energy north of the proposed project in Texas and New Mexico. Load forecasts south of the constraint also indicated an 800-MW reduction in load, further reducing its need. The transmission line would run southwest of Amarillo to an SPS power plant being evaluated for continued operation.

"It's a balancing act. We have to get it right," said Engineering Vice President Lanny Nickell, responding to comments about the additional modeling and studies. "We've probably done more analysis on this single ITP10 than we've done on any number of studies cumulatively. … We need to get better at interpreting these results."

"I look at planning as a core fundamental of the RTO," said MOPC Vice Chair Todd Fridley of Transource Energy. "If we can't do that well and have these fits and starts, we're not getting the job done.

"Major input changes at the end of the planning process makes this determination more difficult. Everyone wants to build the right projects, but we must also maintain the integrity of the planning process so that everyone has confidence that we are delivering customer value," Fridley said.

ITC Holdings' Alan Myers, who chairs the Economic Studies Working Group that brought forward the staff recommendation, reminded members that SPP's new transmission planning process will include accountability mechanisms designed to promote timely data exchanges, reviews and approvals. (See "SPC, MOPC Approve Improvements to SPP's Tx Planning Process," *SPP Strategic Planning Committee Briefs*.)

"One of the core tenets in the new process is more stakeholder discipline," he said. "There will be some bright lines about when we need to have your data in. What we have here is a little more unprecedented."

"What SPP did was go back and do a fair assessment with the stakeholders that were involved," said Bill Grant, director of strategic planning for SPS. "This evaluation is showing that, yes, if we had 8 [GW] of wind, transmission has to be built."

MWG Closing out MMU's Recommendations

The Market Working Group took another step toward closing the 2014 State of the Market Report's nine proposed market

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SPP Hopes Congestion Rights Rule Change Wins FERC OK

By Tom Kleckner

TULSA, Okla. — SPP's Markets and Operations Policy Committee approved a revision request to comply with FERC guidance on the RTO's disparate treatment of point-to-point (PTP) and network integration transmission service (NITS) during periods of redispatch.

MRR202 would allow NITS to be eligible for auction revenue rights for limited times of the year and only for the service not subject to redispatch. NITS would not be eligible for long-term congestion rights (LTCRs), because it does not have continuous service for the entire transmission congestion rights year.

The change is in response to FERC's September order that raised concerns that allowing network service subject to redispatch prior to necessary upgrades being constructed could result in a decrease in allocated ARRs for other transmission customers, along with their ability to nominate LTCRs. The commission ordered a Section 206 proceeding and directed SPP to limit the eligibility for network customers' ARRs and LTCRs with service subject to redispatch. (See *FERC: SPP Treating P2P Customers Unfairly on Congestion Rights*.)

"Our preliminary review indicates that SPP should not provide network service customers subject to redispatch with any LTCRs until the transmission upgrades are placed into service and the service is no longer subject to redispatch," FERC said in the order (ER16-1286, EL16-110). "The commission notes that this approach would be consistent with SPP's rationale for not providing point-to-point customers subject to redispatch with LTCRs."

The 206 proceeding sought to determine whether NITS subject to redispatch while necessary transmission upgrades are being constructed should warrant the same treatment as PTP. SPP responded in December, asking that it be allowed to run the issue through the stakeholder process before FERC takes action.

Stakeholders rejected SPP's recommended approach to allow ARRs until the end of the allocation year following the revisions' effective date. With the change, eligibility limitations only apply to new NITS service after effective date, and current NITS service is "grandfathered" to receive current treatment for the service's term.

SPP staff said it was concerned with the network service exemption because it interprets the order to mean that FERC is exempting awarded ARRs, and future nomination processes should treat NITS and PTP similarly.

"The way we interpret it, FERC is saying any firm transmission service with redispatch should be able to nominate for ARRs or LTCRs, period," said Richard Dillon, SPP's director of markets. "You can't pull them back, but you don't issue any more."

Enel was the lone member to oppose the motion, saying the Tariff changes should apply prospectively to FERC's refund date of Sept. 29, 2016. It proposed its own approach to a LTCR allocation methodology, which it said would ensure firm customers not subject to redispatch are given priority eligibility.

"We believe FERC was very clear that SPP's method of allocating ARRs and LTCRS is unjust and unreasonable," said Enel's Lisa Szot.

Oklahoma Gas and Electric's David Kays, chair of the Regional Tariff Working Group, said about 75% of the stakeholders' recommended language aligns with FERC's directive. "Where it's different is the next allocation period," he said. "That's where it deviates from FERC's suggested language." The working group backed the changes.

Asked why SPP did not just use FERC's suggested language, Dillon said the commission's language is "80% of the way there."

"We added … a single sentence that grandfathered the historical network dispatch," he said. "FERC found that ARRs granted to customers should not continue past the current year. We're saying that the effective date should be as of Sept. 29, 2016, or the date FERC issued its order in this proceeding."

Staff said the commission intends to issue a final order by May, assuming it has a quorum by then.

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changes by securing approval of a revision request that removes the day-ahead must-offer requirement.

The change request, MRR125, came out of the Market Monitoring Unit's recommendations to improve the Integrated Marketplace and was designed to run in parallel with revisions to physical withholding rules. The MOPC declined to take up the revision request in July to allow for further discussion on the rules. (See "MOPC Defers Action on Must-Offer Rule," *SPP Markets and Operations Policy Committee Briefs*.)

Working group Chair Richard Ross of American Electric Power said the group spent considerable time since then discussing the issue. In February, it rejected a revision request that would revise the physical withholding rules to include a penalty for noncompliance. The MMU has appealed that decision and plans to bring it up at the July MOPC meeting.

"The conclusion was a preference to stay with current monitoring activities," Ross said. "It's important you realize whether these provisions are in or out, you're still subject to physical withholding" prohibitions."


McQueen

MMU Director Alan McQueen was asked if the unit agreed with the MWG's conclusion.

"We think the market has the right incentives," McQueen said. "[MRR125] doesn't eliminate concerns around potential cases of physical or economic withholding in the market. We think the rules can be improved, but we don't think the day-ahead must-offer significantly contributes to that."

MOPC Chair Paul Malone, with the Nebraska Public Power District, asked McQueen

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whether he had any concerns over "after-the-fact" market power.

"[Market participants] may not know when they have local market power," McQueen said, "but generally, from experience, MPs should be able to discern when they're likely to have market power."

"The [MWG's] concern was there may be particular conditions on the grid, like transmission outages, planned and unplanned, where a unit may find itself in a situation where it has market power," Ross said. "The concern on MPs' part was we may not be as smart as the MMU staff thinks we are."

Ross said eight of the nine 2014 recommendations are closed, though McQueen disagreed.

"Richard represents the MWG, I represent the MMU," he said.

McQueen took the opposing side when the MOPC then considered MRR214, which would allow market participants to add a 10% buffer to mitigated offers.

The MWG said the 10% buffer added to the mitigation offer will give MPs more margin for error when submitting their mitigated offer curve. The group also said the change would improve price formation in SPP's markets by removing a penalizing feature that may be suppressing offered prices today.

"Mitigation and economic withholding are trying to keep the market at competitive levels when there is the presence of market power," McQueen said. "Are we accomplishing that? Are we improving that? Are we making it better? Is this making sure the market stays competitive during those periods when mitigation actually goes into effect?

MOPC Chair Paul Malone (left) and Vice Chair Todd Fridley | © RTO Insider

"What's being proposed is inconsistent with what we've seen in other markets and what's been approved by FERC," he said.

"This came across because of a discussion at the Board of Directors," said Golden Spread Electric Cooperative's Mike Wise, who sits on the Members Committee and chairs the Strategic Planning Committee. "Many MPs have encouraged us to do this. They're not recovering their short-term marginal costs."

"This needs more work," said Lincoln Electric System's Dennis Florom. "I don't see staff supporting it, I don't see the MMU supporting it. We're going to have our own members and the MMU fighting at FERC, which is embarrassing to me."

The committee sent the revision request on to the board for its approval next week, with seven members opposing and five abstaining.

Separately, Ross recommended the committee reject RR201, which would have provided market participants a mechanism to settle day-ahead market errors without repricing and re-clearing the entire market.

"The challenge folks encountered was if we do that without resettling the whole market, you're just throwing it in a bucket and spreading it across the whole market," he said.

The MOPC agreed, though two members opposed and another dozen or so abstained.

Another change (MRR209) that would have expanded resources' "status options" to include start-up/shut-down and testing was rejected on a roll-call vote, with 61% of the members opposed.

SPP staff said the change would "result in a clearer understanding" of why a resource may not be following dispatch instructions. However, it drew opposition from members who couldn't balance the revision's minimal benefits with its estimated $22,000 cost when operators will continue follow-up phone calls for reliability reasons.

The committee also approved MRR203, which adds a "last-chance" second set of auction revenue rights nominations in the monthly ARR process, where any source-to-sink path can be nominated.

MOPC Endorses Re-evaluation of Basin Electric Project

The MOPC endorsed Basin Electric Power Cooperative's request for an expedited re-evaluation of a 345-kV project in northwestern North Dakota. The project — replacing a 33-mile, 115-kV line at an estimated cost of $52.3 million — was approved last July for a notification to construct with conditions (NTC-C) out of the 2016 Near-Term assessment. (See "First Competitive Tx Project Pulled; ND 345-kV Line Approved," *SPP Board of Directors and Members Committee Briefs*.)

Basin Electric had projected 2.5% load growth in the nearby Bakken shale play in making its earlier request, but updated load forecasts from its member companies have revised that number downward. It asked for the expedited assessment to confirm the timing of construction and associated financial expenditures.

"We're still seeing load increases in that area, just not at the rate we anticipated," said Jason Doerr of Basin Electric member Northwest Iowa Power Cooperative. "It's still Basin Electric's belief that this load will continue to grow at a rate that's significantly less. Next year, wherever the economy goes, we'll have another load forecast to provide SPP."

SPP's Jason Davis said the project could eventually fall under FERC Order 1000, but until then, "We want to take a step back, see what needs and issues still exist going forward."

Another project did proceed as a potential seams project, with the MOPC's approval of a 50-MVAR reactor at a 345-kV substation near Springfield, Mo. The Seams Steering Committee and Transmission Working Group both recommended the project's approval out of the regional-review process. The project was identified last year in a joint study with Associated Electric Cooperative Inc.

The MOPC also approved the TWG's 2017 ITPNT, which includes 16 reliability projects at a combined cost of approximately $60

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million, and its scope for the 2018 ITPNT. Both motions passed unanimously.

Cost Allocation Review Cycle Could Extend to 6 Years

The MOPC approved a task force's unanimous recommendation and an accompanying revision request that future regional cost allocation reviews (RCARs) be conducted at least once every six years, doubling the previous three-year timeline.

The Regional Allocation Review Task Force said extending the timeline would save SPP manpower and consulting costs, noting the most recent RCAR showed an increase in benefit-to-cost ratios and only one entity below the threshold. Ross, the RARTF's vice chair, pointed out the Tariff still allows members to seek relief for an out-of-cycle RCAR at any time from the board, MOPC or Regional State Committee.

"It's not a trivial task. We're spending well over $400,000 to produce the reports," Ross said. "It is quite literally a single-word change."

The motion was opposed by the City of Springfield, whose transmission zone in southwestern Missouri was found to be deficient by RCAR II, and several other smaller entities. The Morgan project — a new 345/161-kV transformer at AECI's Morgan substation and an uprate of a connecting 161-kV line at an estimated $9.2 million — was approved out of the 2017 ITP10 in January as a remedy to Springfield's deficiency, and was recommended for regional funding by the MOPC last week. However, the project is contingent on reaching an agreement with AECI, which would not see reliability benefits from a potential seams project that sits within its service area.

Jeff Knottek, director of transmission planning and compliance for Springfield utilities, said if the Morgan project doesn't provide the city with a remedy, it didn't want to wait another six years.

"We're still technically a harmed entity through two RCARs," said Knottek, who abstained from the vote. "We haven't climbed out of the hole yet, and [Morgan] could fall on its face. Under a worst-case scenario, in six more years we could be sitting [at a negative number]."

Changes Proposed for Revision Process

SPP staff introduced potential changes to the revision-request process for technical documents that don't require MOPC approval.

Staff said NERC reliability standard IRO-010-2, which requires the reliability coordinator (RC) to maintain documentation of data specific to its responsibilities, and a recent revision request that would create RC and balancing authority data as an appendix to the operating criteria, created a need to manage other documents not a part of the current process.

While the revision process for technical documents would not require MOPC approval before being enforced, the committee would still hear appeals from members. Written reports on the changes would be provided in the MOPC's background materials, and members could request discussion on the changes if they're not part of the working groups responsible for the documents.

Staff said the revised process would better meet NERC requirements and proposed starting with reliability data specifications and the communication protocols. Other documents that could fall into the process include the Integrated Transmission Planning manual, the balancing authority's emergency operations plan, the SPP Reliability Coordinator Area's restoration plan and other technical handbooks and guides.

Several stakeholders, primarily from smaller members, expressed concerns over losing visibility into changes.

"Letting [the documents pass] out of the primary working group … how would we know they have passed?" asked ITC Holdings' Marguerite Wagner. "How would we keep track of that?"

"As the organization gets bigger and bigger in geography and more members, I'm not comfortable with this," said Chairman Malone, referring to extending the process to other SPP documents. "In our organization, we try to have someone plugged in to every working group, but not everyone can do that. I'm just not comfortable with it yet."

Monroe said the primary working groups and staff would be responsible for notifying all parties of pending changes, and that some of the more technical revisions would be included on the MOPC consent agenda. He also said he had heard support for giving the working groups the ability to approve technical documents, rather than send them to the MOPC.

Staff said it will return with a formal proposal for the committee's July meeting.

Org Chairs also may See Changes


Suskie

Paul Suskie, SPP's legal counsel and corporate secretary, shared the Corporate Governance Committee's proposed bylaw change for organizational group chair and vice chair selections.

Under the changes, group chairs would be nominated by the committee and appointed by the board to a term that coincides with the board chair's two-year term. Vice chairs are elected by the groups' members, with their terms now coinciding with the group chairs'. The MOPC vice chair would be elected by the board.

Should there be a vacancy at the chair level, the vice chair would become the interim chair until a replacement is appointed by the board to fill out the remainder of the term.

The working group leadership's terms would be staggered to expire in even or odd years. Committees reporting to the board would have their leadership's terms match that of the board chair. This doesn't apply to those committees advising the board, such as the Regional State Committee and the Cost Allocation Working Group.

Upon board approval, the bylaw changes would be filed with FERC for its approval.

MOPC Approves Doubling Credit Allowance to $50M

SPP will join its RTO/ISO brethren in adopting a $50 million unsecured credit allowance should the board next week approve a revision request raising its current cap from $25 million.

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SPP is the last of the RTOs without a $50 million allowance cap. CPWG-RR218 calls for raising the allowance to reduce the costs of capital for utilities, while exposing SPP's customers to "minimal additional credit default risk."

FERC Order 741 allowed RTOs and ISOs to grant up to $50 million in unsecured credit, a limit most grid operators have adopted.

The Credit Practices Working Group's revision was pulled from the consent agenda over concerns that SPP was planning to raise its cap just to match other RTOs. However, staff said SPP's transmission congestion rights market, with its collateral requirements, highlighted the need to revisit the cap.

Staff estimated the increase would affect about 15 credit customers. The revision was approved unanimously by the MOPC.

Twelve other revision requests also passed unanimously as part of the consent agenda:

- BPWG-RR207: Aligns the business practices with the Integrated Marketplace's tag-denial criteria.
- MWG-RR200: Allows bilateral settlement statements (BSS) at a withdrawal point to be included in the overcollected losses calculation. Capping the BSS at the maximum amount of the real-time withdrawal minus any amount of grandfathered agreements or any federal service exemptions will diminish the dilution at a generation or hub settlement location.
- MWG-RR205: Allows the implementation of the combined-resource option changes by including the minimum regulation-capacity operating limit, and adds resource offer parameters that can be changed daily for a jointly owned resource's minimum physical capacity and physical-regulation capacity operating limits.
- MWG-RR216: Reinstates Tariff language omitted from RR173 and filed at FERC last year related to eligibility of multi-configuration resources for regulation-up or regulation-down service.
- MWG-RR217: Removes Tariff language related to violation relaxation limits to make the section consistent with a compliance filing to FERC's Order 825 on shortage pricing.
- MWG-RR219: Ensures language in SPP's Tariff meets FERC requirements for enhanced combined cycle units.
- ORWG-RR213: Creates a new appendix to the SPP Operating Criteria that defines how the SPP reliability coordinator will operate voltage stability limited system constraints, as recommended by the Wind Integration Study.
- RTWG-RR208: Implements the Transmission Planning Improvement Task Force's white paper for new regional planning processes by replacing current planning schedules with an annual transmission-expansion plan, creating a standardized scope; establishing a common planning model for use across the various planning processes; and creating a staff/stakeholder accountability program. (See "SPC, MOPC Approve Improvements to SPP's Tx Planning Process," *SPP Strategic Planning Committee Briefs*.)
- RTWG-RR211: Establishes an additional criterion for competitive projects, requiring that the total competitive segments for a transmission project cost meet or exceed $3 million.
- TWG-RR224: Aligns the existing criteria with NERC's new definition of special protection schemes as remedial action schemes, and cleans up planning-criteria language coinciding with changes made to the operating-horizon system operating limits methodology.
- TWG-RR215 and TWG-RR186: Eliminates redundant requirements.

— Tom Kleckner

FERC NEWS

FERC: Gas Continued to Dominate in 2016

Warmest Winter Ever Drove down Gas, Electricity Prices

By Michael Brooks

Record warmth, combined with one of the largest increases in pipeline capacity in U.S. history, led to record-low gas prices last year, FERC said in its annual State of the Markets Report, released Thursday.

The 2015-2016 winter was the warmest on record for the continental U.S., with temperatures nearly 5 degrees above the 20th century average, according to the National Oceanic and Atmospheric Administration.

"Above average temperatures in the 2015-2016 winter limited natural gas demand during the first three months of the year, leading to robust storage inventories at the start of the 2016 injection season in April and reduced demand for storage injections through the summer," FERC said. "Prices fell to record lows in the first half of 2016, before climbing thorough the second half of the year driven by steady domestic demand, rising exports and a drop in production."

Henry Hub prices averaged $2.48/MMBtu, the lowest in 20 years and a 5% decrease from 2015. While prices fell across the country in 2016, the Northeast saw the most dramatic decreases, with New York City prices falling 42%. The region, however, saw a spike in prices last month. (See related story, *Gas, LMPs Rebound in NY, New England in March*, p.12.)

The low prices are made even more notable by the fall in supply. Gas production fell 2.5% last year, averaging 72.3 Bcfd, as overall domestic demand only rose 1% to 75.6 Bcfd. This was the first year-over-year drop in production since 2005, FERC said. However, the commission expects that production will rebound this year, "driven by a projected 26% increase in oil and gas exploration and production investment," it said.

Prices will also remain low this year, the report said, because of the amount of new pipeline capacity. 2016 saw 7.1 Bcf go into service, and more projects are expected this year, with three into Mexico. Exports to the country grew 24% to 3.6 Bcfd, marking the sixth year in a row they have increased.

Storage withdrawals at the beginning of the year totaled 1.8 Tcf, the lowest in four years, and as a result, inventories stood at 2.5 Tcf in April, a record high. Inventories set another record at the end of the injection season as well, with 4.047 Tcf in storage in November.

Because winter 2016/17 was not quite as warm as 2015/16, gas demand from residential and commercial increased by 12% in December, compared to the same month in 2015. However, this winter made headlines for its brevity, with February 2017 being the second-warmest February on record. Last month, the Energy Information Administration reported the first-ever gas injection in February.

Gas Overtakes Coal; Renewables Continue Gains

While gas demand from the residential and commercial sectors fell 5.1%, this was partially offset by a 4% increase from power generators. 2016 was a landmark: While gas' growth slowed (demand increased by 17% in 2015), it became the primary source of electricity generation nationally in 2016, the first time ever on an annual basis, according to EIA data. Gas generated 34% of U.S. electricity, compared to 30% from coal.

The U.S. added more than 27 GW of generating capacity in 2016, according to EIA. About a third of this were new natural gas plants, while about 10 GW of coal plants retired.

Most of the remaining additions were utility-scale renewable resources. The U.S. added 8.7 GW of wind and 7.7 GW of solar in 2016, according to EIA. The commission said renewables were buoyed by the extensions of the production and investment tax credits, as well as several increases in state renewable portfolio standards.

Additionally, despite the retirement of the 478-MW Fort Calhoun nuclear plant in October, the completion of Watts Bar Unit 2 that same month led to a slight net increase for nuclear capacity. FERC expects the increase to be short-lived, however, as numerous plants are expected to retire in the next few years. The fate of two under-construction plants in the Southeast are in doubt following the bankruptcy of Westinghouse Electric last month.

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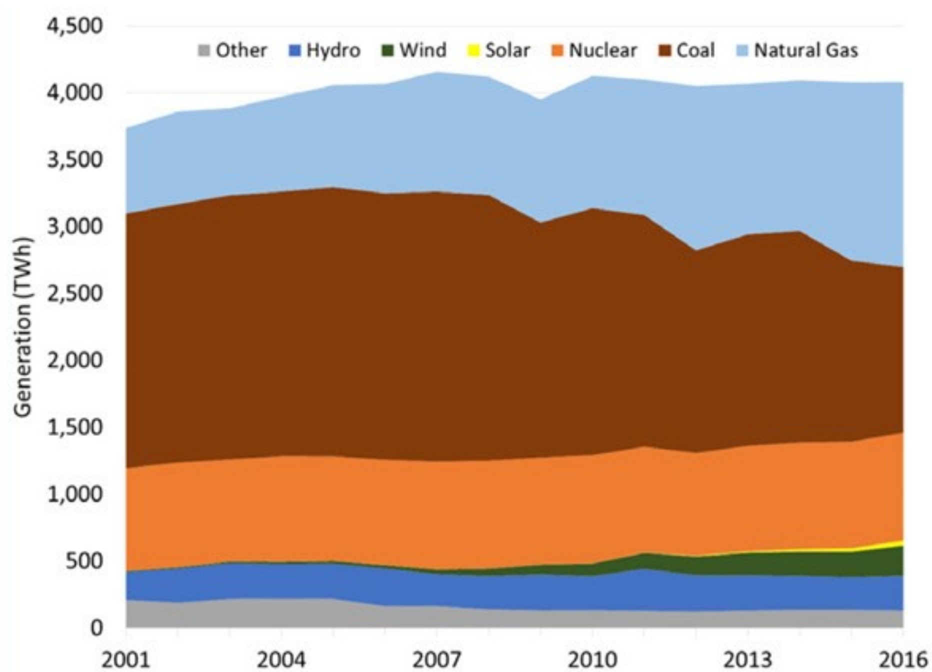

Utility-scale net generation by fuel type in 2016 | *FERC/EIA*

FERC News

FERC: Gas Continued to Dominate in 2016

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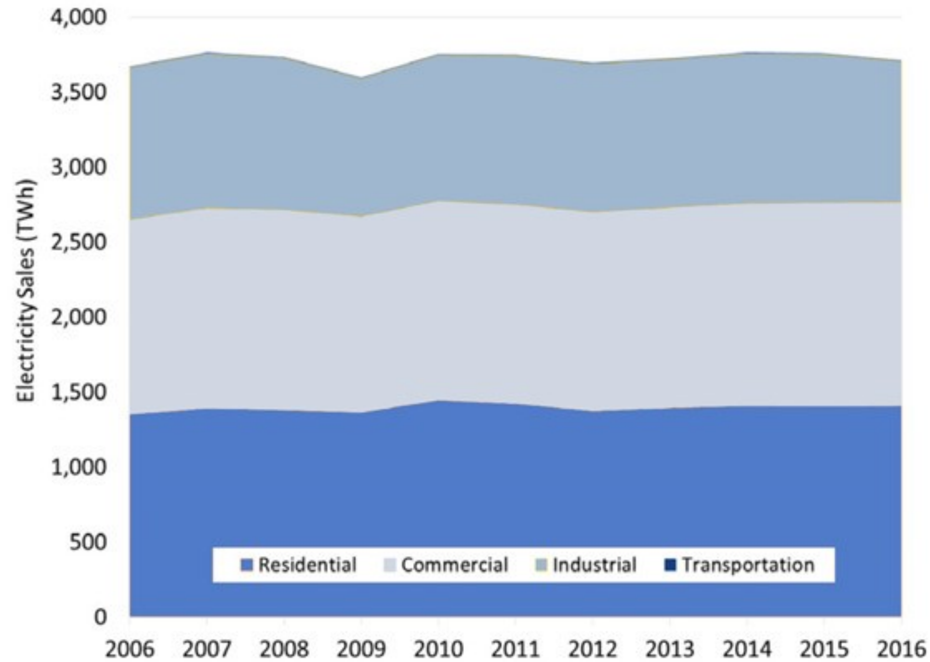
Net Metering Contributing to Low Electricity Demand, Prices

Thanks largely to cheap gas, power prices were down across most of the country, with PJM recording the lowest LMPs since the RTO's formation in 1999. (See *PJM Monitor Concerned About State Subsidies*.) Like gas prices, New York and New England saw the biggest drop.

Total electricity sales fell 13% from 2015, even as the U.S. economy experienced steady growth. FERC attributed this to the warm winter and increased energy efficiency.

The commission also noted that net metering from rooftop solar is reducing demand for wholesale power. According to EIA, distributed solar capacity increased by 3.4 GW last year.



Electricity demand by sector | *FERC/EIA*

"Although net-metered projects largely participate in retail markets, their aggregate impact has begun to affect wholesale markets with large penetration of distributed solar projects," FERC said. "These impacts can largely be seen as a functional reduction on demand from the RTO/ISO perspective, with subsequent shifting of system load curves."

Court Rejects FERC ROE Order for New England

Continued from page 1

"Because FERC failed to articulate a satisfactory explanation for its orders, we grant the petitions for review," a three-judge D.C. Circuit Court of Appeals panel ruled in an opinion written by Senior Judge David B. Sentelle. The court vacated the order and remanded the case to the commission for additional proceedings (15-1118).

It is unclear how the court's ruling will ultimately affect the rates for the TOs, which include Emera Maine, Northeast Utilities, Central Maine Power, National Grid and NextEra Energy.

Much may depend on who is appointed by President Trump to fill the vacancies that have left FERC with only two commissioners, one short of a quorum. "Under a new FERC composition, nominally under a 'pro-infrastructure' administration, there is potential for the environment to be more favorable for transmission ROEs," UBS Securities analyst Julien Dumoulin-Smith said in a research note Monday.

But the court's ruling provided ammunition for state officials seeking a lower rate, saying FERC's analysis was "unclear."

Attorney David Raskin, who argued the case for the TOs, referred questions to Emera, which did not respond to requests for comment. A spokesperson for the Connecticut attorney general's office said it was reviewing the decision and declined further comment. FERC also declined to comment.

2014 Ruling

In the 2014 ruling, the commission voted 4-0 to change the way it calculates ROEs for electric utilities, moving to a two-step discounted cash flow (DCF) process it has long used for natural gas and oil pipelines that incorporates long-term growth rates.

But the commission split 3-1 over its first application of the new formula, tentatively setting the ROE for the New England TOs at three-quarters of the top of the "zone of reasonableness," a departure from the prior practice that used the midpoint in the range (EL11-66-001). (See *FERC Splits over ROE*.)

The commission's ruling resulted from a complaint filed in 2011 by New England state officials and others who contended the 11.14% base ROE was unreasonable because interest rates had fallen since the commission established it in 2006.

Both the New England TOs and state officials representing customers appealed FERC's order to the D.C. Circuit, saying the commission had failed to meet the requirements under FPA Section 206 for setting a

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FERC NEWS

Court Rejects FERC ROE Order for New England

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"It is not our job to tell FERC what the 'correct' ROE is for transmission owners, but it is our duty to ensure that FERC's decision 'is the product of reasoned decision-making.'"

D.C. Circuit Court of Appeals

new ROE. The appeals followed a second FERC order rejecting rehearing requests.

The TOs and customers did not challenge FERC's use of the two-step methodology or the resulting zone of reasonableness, which the commission tentatively set as 7.03 to 11.74%, a reduction from the 2006 ruling that set the range at 7.3 to 13.1%. Rather, they challenged FERC's setting of the base ROE within the new zone.

The TOs said the order should be vacated because it failed to find that the existing ROE was unjust and unreasonable before setting a new ROE. The states contended that FERC arbitrarily placed the new ROE at the midpoint of the upper half of the zone of reasonableness.

Section 205 vs. Section 206

FERC's authority to set transmission rates is governed by Sections 205 and 206 of the Federal Power Act.

TOs may seek a rate change under Section 205 and are not required to show that a previous rate was unlawful. But the states' challenge that prompted the 2014 order was filed under Section 206, which requires FERC to determine whether an existing rate is unjust and unreasonable before it can impose a new rate. "The burden of demonstrating that the existing ROE is unlawful is on FERC or the complainant, not the utility," the court noted.

Instead of first finding that their base ROE was unjust and unreasonable, FERC decided that 10.57% was the just and reasonable base ROE and that the existing 11.14% ROE was unlawful as a result, the TOs said.

FERC contended its determination of a new just and reasonable base ROE was "sufficient" by itself to prove that the existing ROE was unjust and unreasonable.

The court disagreed. "Because it was a Section 206 proceeding, rather than a Section 205 proceeding, FERC bore the burden of making an explicit finding that the existing ROE was unlawful before it was authorized to set a new lawful ROE. FERC, however, never actually explained how the existing ROE was unjust and unreasonable," the court said.

"Although we defer to FERC's expertise in ratemaking cases, the commission's decision must actually be the result of reasoned decision-making to receive that deference. Without further explanation, a bare conclusion that an existing rate is 'unjust and unreasonable' is nothing more than a talismanic phrase that does not advance reasoned decision-making."

ROE Incentives

Because FERC failed to meet its dual burden under Section 206, the court said it did not need to rule on the TOs' complaints that the commission's ruling also violated their due process rights by failing to put them on notice that it would reconsider previously approved ROE incentives in addition to the base rate.

The states challenged only the TOs' base ROE, and not the incentives. But because the ruling reduced the upper end of the zone of reasonableness from 13.1% to 11.74%, FERC noted that the TOs' total ROE including incentives must remain within the zone. Although the commission chose a higher position within the range, the TOs' ROE was reduced because the new formula reduced the top end of the zone.

Where in the Zone?

In setting the ROE at the 75th percentile of the zone, the commission majority sided with the TOs and rejected arguments by FERC trial staff and consumer representatives, who had argued for continuing the commission's traditional use of the zone's midpoint, which would have put the ROE at 9.39%.

Commissioners Cheryl LaFleur, Philip Moeller and Tony Clark said the change was justified because of the unusually low interest rates at the time; it had "less confidence" that "a mechanical application" of the midpoint of the DCF zone would result in an ROE high enough to allow the TOs to attract investment capital. Commissioner John Norris dissented, saying there was insufficient evidence to support setting the rate so high.

The court questioned the FERC majority's reasoning.

"On the one hand, it argued that the alternative analyses supported its decision to place the base ROE above the midpoint, but on the other hand, it stressed that none of these analyses were used to select the 10.57% base ROE."

FERC said "alternative benchmark methodologies" and additional evidence supported its conclusion that the midpoint would be too low. But the court said "none of the analyses necessarily suggested that a 10.57% ROE was a just and reasonable base ROE. Thus, the only conclusion FERC drew from these analyses was that transmission owners were entitled to an ROE somewhere above the 9.39% midpoint."

The court noted that 10.57% was higher than 35 of the 38 data points FERC used to construct its DCF zone of reasonableness. It also said 89% of the state commission-authorized ROEs that FERC consulted were below 10.57%.

FERC also cited three alternative benchmark methodologies as "informative." The risk premium analysis supported a base ROE between 10.7 and 10.8%; the Capital Asset Pricing Model produced a midpoint of 10.4%; and the expected earnings analysis had a midpoint of 12.1%.

"It is not our job to tell FERC what the 'correct' ROE is for transmission owners, but it is our duty to ensure that FERC's decision is 'the product of reasoned decision-making,'" the court said. "While the evidence in this case may have supported an upward adjustment from the midpoint of the zone of reasonableness, FERC failed to provide any reasoned basis for selecting 10.57% as the new base ROE."

— Michael Kuser contributed to this article.

Company Briefs

Idaho Power Requests Additional $10.6M from Ratepayers

Idaho Power asked state regulators for permission to raise its rates enough to generate an additional $10.6 million next year in its annual power cost adjustment filed last week.

If the Public Utilities Commission approves the request, the typical residential customer using 1 MWh/month would pay an additional 59 cents effective June 1.

Included in the proposal is a refund of about $13 million to customers coming from previously collected energy efficiency rider funds.

More: Idaho Press-Tribune

IKEA Installing Largest Retail Solar Rooftop in Ind.

When IKEA opens its new store in Fishers, Ind., this fall, it will have the largest retail solar rooftop in the state.

Installation of the store's 3,888 solar panels is scheduled to start later this spring with a completion goal of this summer, IKEA officials said.

The Fishers store will be IKEA's 47th solar project in the U.S. The company has installed solar in nearly 90% of its U.S. locations and plans to invest $2.5 billion into renewable energy through 2020.

More: WRTV

Alliant's Riverside Plant out of Service Pending $25M Repair

Alliant Energy confirmed last week that its Riverside power plant in Beloit, Wis., has been out of service since September and is not expected to restart until July. The utility had previously reported the outage to the Public Service Commission and MISO, but not to the public.

The natural gas-fired plant, which generates 675 MW of electricity, was closed in September for regular maintenance. When Alliant tried to turn it back on in November, the plant would not start properly, and a steam turbine was discovered to have internal damage, spokesman Scott Reigstad said. He said it would cost $25 million to fix the turbine.

Reigstad said he does not anticipate any power shortages arising from the closure.

More: La Crosse Tribune

SCANA May Abandon Nuke Project Amid Westinghouse Bankruptcy

SCANA, which is the utility that has been building two new nuclear reactors at the V.C. Summer Nuclear Station in Jenkinsville, S.C., told state regulators Wednesday that abandoning the project is an option under consideration in the wake of Westinghouse Electric's bankruptcy filing.

SCANA CEO Kevin Marsh said the company is in its 30-day evaluation period and may need more time to determine how it will proceed. He indicated it is also pursuing options for completion of the $14 billion project with or without Westinghouse.

The first reactor at V.C. Summer was expected to go online in 2019, with the second going online a year later.

More: The Associated Press

APS to Issue RFP for Peaking Capacity on April 21

Arizona Public Service will issue a request for proposals on April 21 seeking about 400 to 700 MW of capacity to meet peak demand from June through September beginning in 2021.

Proposed projects must be able to begin delivery by June 1, 2021.

More: Arizona Public Service

SDG&E Affiliate Approved to Lobby While PUC Investigation Continues

Amid an ongoing investigation as to whether it violated state lobbying laws, a San Diego Gas & Electric affiliate has received approval from state regulators to lobby on community choice aggregation.

Provided Sempra Services follows the terms laid out in the Public Utilities Commission's April 6 advice letter, its lobbyists can now meet with elected officials or do other work to market against community choice.

Previously, people working for Sempra Services met with elected officials. An SDG&E spokeswoman said in an email that the utility believes Sempra Services was approved last summer, so the lobbying done up until now did not violate state law.

More: KPBS

NVE Meets State Renewable Goals for 7 Years Straight

NV Energy is on a seven-year streak of meeting its mandated renewable energy goals in Nevada, according to a filing with the Public Utilities Commission.

In 2016, the utility achieved a 22.2% renewable credit level in the southern part of the state and a 26.6% level in the northern part.

Last year, the legislative requirement was 20%, based on total retail energy sales. The requirement rises to 25% in 2025.

More: Las Vegas Sun

Mont. Bill to Recoup Colstrip Losses Stalls in House Panel

A bill that would have required Talen Energy to pay for the economic losses caused by the partial shutdown of the Colstrip power plant stalled in a Montana legislative committee last week.

The House Energy, Technology and Federal Relations Committee failed to advance the bill on an 8-8 vote. The proposed measure would have required Talen and plant co-owner Puget Sound Energy to submit a closure plan addressing lost property values, worker retraining, lost state and local tax revenue, and local government's bond liabilities.

Pursuant to a legal settlement, the two older units of the coal-fired plant must close by July 2022.

More: The Associated Press

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COMPANY BRIEFS

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Toshiba's Projected Loss Swells From Westinghouse Bankruptcy

Toshiba, whose U.S. nuclear unit Westinghouse Electric filed for Chapter 11 last month, reported unaudited earnings last week for the December quarter after two delays and projected a $9.2 billion loss for the fiscal year that ended in March.

For the April through December 2016 period, the company reported a $4.8 billion loss. In February, it had projected a $3.5 billion loss for the fiscal year, but the projected loss swelled because of losses related to Westinghouse's bankruptcy filing, the company said.

Toshiba's auditor, PricewaterhouseCoopers Aarata, said it couldn't be certain that earlier accounting for Westinghouse was proper.

More: The Associated Press; MarketWatch

Robin Lunt Joins Wilkinson Barker Knauer

Robin Lunt is joining the law firm of Wilkinson Barker Knauer as of counsel, primarily advising clients in the firm's energy practice, having served in roles at FERC and the National Association of Regulatory Utility Commissioners.

At FERC, Lunt served as the legal and policy adviser to the firm's now senior adviser Tony Clark during his time as a commissioner. She advised Clark on legal and policy implications for all electricity matters in the western interconnection, gas and oil orders, and major market changes. Prior to joining FERC, she was assistant general counsel at NARUC, where she worked on electricity and natural gas issues.

Most recently, Lunt served as general counsel at energy technology company Innovari.

More: Wilkinson Barker Knauer

Xcel Ends Coal Burning at Valmont Plant

The Valmont power plant east of Boulder, Colo., burned its last trainload of coal on March 3, an Xcel Energy spokeswoman recently confirmed.

In 2010, Xcel announced it would stop burning coal at the plant as part of a plan to cooperate with the Clean Air-Clean Jobs Act that then-Gov. Bill Ritter signed into law.

The plant's coal-fired generator, which had been in operation since 1964, can still operate on natural gas this year, Xcel spokeswoman Michelle Aguayo said. However, she said the company has no plans to repower it with gas in the future.

More: Daily Camera

FEDERAL BRIEFS

Perry Orders Study on How Renewables Affect Baseload

Energy Secretary Rick Perry on Friday ordered a 60-day study of the electric grid to determine whether policies favoring renewables are accelerating the retirement of coal and nuclear plants that provide "baseload power."

Perry asked his chief of staff to develop a plan for evaluating the extent to which regulatory burdens, subsidies and tax policies force the premature retirement of baseload power plants. He also wants to know whether wholesale energy markets adequately compensate for the positive attributes offered by coal and nuclear plants.

Perry requested the study just days after participating in the G-7 Energy Ministerial meeting in Rome, where the need for a diverse supply of electricity was reportedly discussed.

More: Bloomberg

BPA Study: More Capacity Needed for Growing Economy in Ore.

A new study by the Bonneville Power Administration found Central Oregon's transmission grid can support the region's current loads, but additional capacity is needed for its expanding economy.

BPA studied three new interconnection requests for large loads in 2016 and, based on the results, has committed to installing new equipment and performing upgrades that will increase the interconnection capability by 315 MW by June 2019.

Preliminary studies show that with new equipment and schemes, the main grid could support an additional 270 MW of new large load additions, for a total of 585 MW. The schemes require further study and would take an estimated two to three years to implement.

More: KTVZ

Manufacturing Sector Asks DOE not to Expedite LNG Exports

The Industrial Energy Consumers of America sent a letter Thursday to Energy Secretary Rick Perry asking his department to deny expedited approval for export permits for LNG.

The association fears that ramping up LNG exports would reduce domestic supply and raise prices, thus impeding growth in the manufacturing sector.

Charlie Riedl, executive director of the Center for Liquefied Natural Gas, an arm of the Natural Gas Supply Association, countered that the U.S. has more than enough natural gas to benefit from exports and to provide affordable gas at home.

More: FuelFix

Deputy Energy Secretary Pick Donated to Perry

Dan Brouillette, the Trump administration's pick to be deputy secretary of energy, has ties to the Energy Department as an insider and lobbyist — and has donated to Energy Secretary Rick Perry's gubernatorial and presidential campaigns.

Brouillette and his wife jointly donated $5,000 to Perry's 2012 presidential cam-

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FEDERAL BRIEFS

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paign, according to data on OpenSecrets.org. In 2006 and 2009, he donated nearly $2,000 for Perry's gubernatorial campaigns. He also has served as a bundler for Perry, collecting campaign contributions from other donors, and previously donated almost $49,000 to a PAC that contributed to Perry.

From 2001 to 2003, Brouillette served in the Energy Department as an assistant secretary of energy for congressional and intergovernmental affairs. He has lobbied the department while at Ford Motor Co. and D.C. lobbying firms.

More: Bloomberg BNA

Trump Eyes Climate Skeptic to Run Environmental Panel

Kathleen Hartnett White, a vocal critic of climate change science, is a top contender to run the Trump administration's Council on Environmental Quality, according to sources close to the administration.

White is a former chairwoman of the Texas Commission on Environmental Quality and presently works for a conservative think tank in the state. She was a member of President Trump's economic advisory council during his campaign.

In a June op-ed published in the *Austin American-Statesman*, she wrote: "Carbon dioxide is not a pollutant, and carbon is certainly not a poison. Carbon is the chemical basis of all life on earth. Our bones and blood are made out of carbon."

More: Politico

EPA Seeks Input on Which Obama-era Regulations to Repeal

EPA's regulatory task force, established by President Trump's Feb. 24 executive order, wants public input on which of the Obama administration's regulations to repeal, the agency said Wednesday in the *Federal Register*.

"We are supporting the restoration of America's economy through extensive reviews of the misaligned regulatory actions from the past administration," EPA Administrator Scott Pruitt said in a statement.

The public has 30 days to comment.

More: The Hill

Lawmakers Ask Trump to Fill NRC Vacancies

Three members of the House Committee on Energy and Commerce sent a letter to President Trump requesting that he fill current and future vacancies at the Nuclear Regulatory Commission.

Chairman Greg Walden, Subcommittee on Energy Chairman Fred Upton and Subcommittee on Environment Chairman John Shimkus advised that absent the nomination and confirmation of additional commissioners, the commission will lack a quorum on July 1 when Chairman Kristine Svinicki's current term expires.

The letter urged Trump to nominate commissioners so the confirmation process could be completed as soon as possible.

More: House Committee on Energy and Commerce

Trump Officials, Tribal Leaders Discuss Saving Coal Plant

Trump administration officials met Wednesday with Navajo Nation and Hopi leaders to discuss what actions the government could take to save a coal plant on the Navajo reservation from its planned closure by 2019.

Navajo President Russell Begaye said his tribe wants the plant to remain open until 2029. However, if it must close before then, he's asking the Interior Department for access to its transmission lines so that the tribe can generate wind, solar and other renewable energy sources.

Although the tribe doesn't own the plant, 40% of its budget and infrastructure is tied to revenues generated by the plant as well as the Kayenta mine, Begaye said. The four utilities that own the facility said it is no longer economical to operate it.

More: The Hill

UN Deputy Chief: US Must Come Back to Climate Change 'Table'

Noting that the U.S. is a leading emitter of greenhouse gases, the deputy secretary-general of the U.N. said the Trump administration must be "brought back to the table" on climate change notwithstanding repeated threats by the president to leave the 2016 Paris Agreement.

"The U.S. is an important leader in this and we believe that they will do the right thing once they are better informed about it," Amina J. Mohammed said.

Mohammed said it would be "very difficult" for President Trump to make good on his campaign promise to pull out of the deal brokered by President Barack Obama because the U.S. already ratified it and would have to wait three years to announce a withdrawal. Then, it would take another year before the exit process is complete.

More: Newsweek

EPA Budget Asks for More Security for Pruitt

A draft EPA budget requests funds to hire 10 additional security guards to provide Administrator Scott Pruitt with an around-the-clock personal security detail, according to a *New York Times* report.

Myron Ebell, who led President Donald Trump's EPA transition team but is no longer employed by the administration, has indicated that EPA employees and "the left" pose a risk to Pruitt.

The request would more than double the agency's security staff, which typically has consisted of six to eight agents in recent years. EPA chiefs usually only have door-to-door security, *The New York Times* reports.

More: Quartz; The New York Times

State Briefs

CALIFORNIA

SDG&E, SoCalEd Challenge Laguna Beach Ordinance

San Diego Gas and Electric and Southern California Edison filed federal lawsuits Wednesday alleging that Laguna Beach's new utility undergrounding ordinance, which requires that utilities bury new and replacement lines, violates state and federal law.

The utilities allege the law, adopted by the City Council on March 28, is unconstitutional because it conflicts with existing franchise agreements between the city and the utilities, conflicts with the state Public Utilities Commission's fairness rules for customer costs, and impedes safety, utility and maintenance work in the city.

Council member Bob Whalen said the ordinance was enacted to promote public safety. The lawsuits maintain enforcing the ordinance would likely result in service interruptions and safety hazards if SoCalEd were prevented from doing timely maintenance, repairs and in-kind replacements of its existing overhead electric lines and poles.

More: *Laguna Beach Independent*

SoCalEd Creating Fleet of Energy-Efficient Walmarts

Southern California Edison is creating a fleet of energy-efficient buildings at Walmart stores and other locations that will use battery-storage systems and intelligent software to switch from the electric grid to battery power to conserve energy during high-demand periods.

Advanced Microgrid Solutions will be installing its Hybrid Electric Building Technology throughout 2018 at 27 Walmart stores, the California State Office of the Chancellor and California State University, Long Beach. The battery-storage systems at the Walmarts alone will create 40 MW of energy storage.

The chancellor's office is expected to save about $28,000 a year from the system, and the water district is expected to save more than $500,000 per year.

More: *San Gabriel Valley Tribune*

INDIANA

Bill Cutting Net-Metering Rates Heading to Governor


Holcomb

A bill that would in five years drastically cut net metering compensation to bring it in line with utilities' wholesale costs for energy is on its way to Gov. Eric Holcomb after the Senate voted 37-11 to approve changes made to the measure in the House.

The bill would allow customers who install solar panels before 2018 to continue at the current rate for 30 years. Those who purchase panels after that, but before 2022, would receive the rate until 2032.

A spokeswoman for the governor declined to say whether he would sign the bill into law.

More: *The Associated Press*

MAINE

Lawmakers Considering Fate of Renewable Energy Subsidy

A public hearing is set for today for two bills that seek to address the multimillion-dollar subsidy paid by state ratepayers to encourage the use of renewable energy. Biomass plants are the subsidy's primary beneficiary.

L.D. 1147, which is being presented by Democrats, seeks to maintain the state's renewable portfolio standard, which cost ratepayers roughly $12.6 million in 2015, as is. L.D. 1185, presented by House Minority Leader Ken Fredette (R) seeks to update the law. No details were available on Fredette's proposal.

The state's initial RPS, adopted 18 years ago, required at least 30% of total sales from sources including wind, solar, hydro and biomass and set a capacity limit of 100 MW. It was later determined that 30% renewable power was already online, so in 2006 lawmakers dropped the 100-MW cap for wind and upped the 30% goal by a percentage point each year until 2017. The law is up for review because the extra 10% goal for new sources has been met.

More: *Portland Press Herald*

MARYLAND

PSC Allocates Another $48M to Ratepayers for Exelon-Pepco Merger

The Public Service Commission issued an April 12 order allocating an additional $48 million to ratepayers arising from the commission's approval nearly two years ago of the merger between Exelon and Pepco Holdings Inc. The order raises total customer benefits to $175 million.

The additional funds will be used for programs benefiting customers of PEPCO and Delmarva Power & Light. Nearly $22 million will be allocated to energy-efficiency programs in Montgomery and Prince George's counties; $8 million will go to energy-efficiency programs in Delmarva's service territory; $6.7 million will support programs that help low- and moderate-income customers pay their utility bills; $9 million will provide energy-efficiency benefits to commercial and industrial customers; and $2 million will support a review of the state's electric grid.

The commission approved the merger on the condition that state ratepayers would see more money if it turned out that ratepayers in other states got a better deal. The provision was implemented based upon the deal received by ratepayers in D.C.

More: *Maryland Public Service Commission*

MINNESOTA

Camp Ripley Debuts Largest Solar Farm on US National Guard Base

The largest solar farm on any National Guard Base in the U.S., spanning an area about the size of 65 football fields, has been completed at Camp Ripley and will create 10 MW of energy.

The $25 million project, consisting of 116,000 thin-film solar panels, was a joint project of the state National Guard and Minnesota Power.

It will serve all Minnesota Power customers, but all the electricity the array produces can be directed to the National Guard in an emergency, said Al Hodnik, president and CEO of ALLETE, parent company of Minnesota Power.

More: *MPR News*

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State Briefs

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Duluth Launches Pilot Program to Burn Gas at Steam Plant

Duluth has launched a pilot program to reduce by 40% the more than 50,000 tons of coal it burns at its downtown steam plant by switching to natural gas.

The seven-month program is expected to cut the plant's carbon emission by 15%, which amounts to about 13,000 tons.

The project, which required $500,000 to upgrade two boilers so that they could burn natural gas, is part of the city's plan to ultimately convert the plant to a closed-loop, hot water system. City officials are hoping to receive $21 million from the state Legislature. If the money is approved and the project moves forward, the city plans to use other energy sources to heat the water, including solar and biomass harvested from forests in the northeastern part of the state.

More: *MPR News*

Gov. Dayton Vows to Veto Bill Allowing Pipeline to Bypass PUC

Gov. Mark Dayton said he would veto a bill that would allow Enbridge to bypass the Public Utilities Commission and build a $7.5 billion replacement for an aging pipeline that travels through the northern part of the state.

The House of Representatives amended a jobs and energy bill to allow Enbridge to get around regulators in its Line 3 pipeline replacement.

Opponents say the proposed route includes forests and waters that an oil spill could harm. The route also includes treaty lands and waters where the Ojibwe tribe harvests wild rice.

More: *The Associated Press*

NEW YORK

Cuomo Appoints Energy Advisers in Albany

Gov. Andrew Cuomo on Monday announced several grid-related appointments to his administration, including senior policy advisor for energy, deputy secretary for energy and financial services, assistant secretary for energy and assistant secretary for the environment.

The new senior policy advisor for energy, Casey Kuklick, has worked in Cuomo's administration in the Office of Energy and Finance since 2014. Adam Zurofsky has been appointed deputy secretary for energy and financial services after serving as president and founder of Touchstone Metrics, a management consulting firm in New York City.

The new assistant secretary for energy is Peter Olmsted. He served as manager of strategic engagement at the Department of Public Service, where he helped implement Cuomo's Reforming the Energy Vision and the Regional Greenhouse Gas Initiative. Rajiv Shah has been appointed assistant secretary for the environment after serving as a senior environmental policy advisor to the governor. Shah previously worked with the Department of Environmental Conservation.

More: *Gov. Andrew Cuomo*

OHIO

Report Cites 3 Metropolitan Areas for Unhealthy Air Pollution

The state's Akron, Cleveland-Elyria and Youngstown-Warren-Boardman areas were among 72 in the U.S. that experienced more than 100 days of unhealthy air pollution in 2015, according to a report released last week by the Environment America Research & Policy Center.

The report said the Akron area had 188 days of moderate to unhealthy levels of soot particles in the air; Cleveland-Elyria had 175; and Youngstown-Warren-Boardman had 142.

Notwithstanding its inclusion in the report, Cleveland showed its lowest particulate pollution data in history. Last year, two studies ranked Cleveland as the 11th and 34th sootiest city in the country.

More: *The Plain Dealer*

OREGON

Portland, Multnomah County Aim for 100% Renewable Energy by 2050

Portland and Multnomah County have made it their goal to transition to 100% renewable energy by 2050, top elected officials announced last week.

Portland Mayor Ted Wheeler said the city is committed to using renewable sources to satisfy all electricity needs by 2035 and to transition away from all remaining dirty energy sources, primarily fossil fuels in the transportation sector, by 2050. The city already has a climate action plan that calls for an 80% reduction of carbon emissions from 1990 levels by 2050.

Other plans include renovating the Portland Building to meet LEED Gold status, which will reduce energy use by 20%. Additionally, the Multnomah County Courthouse and Health Department, which are presently under construction, will be LEED Gold certified and will be able to operate with 40 to 50% less energy than comparable facilities.

More: *The Oregonian*

PENNSYLVANIA

New Coalition Will Fight Bailout for Nuclear Plants

Beaver Valley nuclear plant, located near Shippingport, Pa.

Seventeen interests ranging from the natural gas industry, to power plant operators, to major manufacturers, to consumer advocacy have formed a coalition to oppose bailing out the state's financially struggling nuclear power industry.

Citizens Against Nuclear Bailouts formed after lawmakers from both parties and both chambers of the state's General Assembly announced in March that they had formed a nuclear caucus to explore ways to ensure the survival of the state's five nuclear power plants. The caucus, which presently includes 73 members, has not yet decided upon a strategy.

Steve Kratz, a coalition spokesman, said the nuclear industry can't become competitive without a cost increase to consumers.

More: *Pittsburgh Post-Gazette*