RTO Insider

Your Eyes and Ears on the Organized Electric Markets

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

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FERC Upholds Storage Order

By Rich Heidorn Jr.

FERC on Thursday rejected multiple requests to reconsider its landmark electric storage order, prompting a partial dissent from Commissioner Bernard McNamee over requests to allow states to opt out (RM16-23-001, AD16-20-001, *Order No. 841-A*).

The majority rejected requests that it allow relevant electric retail regulatory authorities (RERRAs) the ability to opt out of its storage provisions, as the commission did for demand response under Order 719. The commissioners also rebuffed questions about their authority to require that power sold by RTO markets to an electric storage resource (ESR) for resale be at the wholesale LMP.

Dissent

McNamee's 13-page dissent said the majority "fails to recognize the states' interests in ESRs located behind a retail meter (behind-the-meter) or connected to distribution facilities."

"I believe Order Nos. 841 and 841-A are on solid footing when they deal with ESRs connected to the transmission system and how ESRs may participate in the wholesale market, and I concur in those aspects of today's order. I am troubled, however, that the storage orders do not fully respect or consider the impact they may have on local distribution systems, the states that regulate those local distributions systems and local retail customers," McNamee wrote.

McNamee said he would have reconsidered the commission's finding that it has jurisdiction over whether ESRs located behind the meter or on a local distribution system are permitted to participate in the RTO/ISO markets through the ESR participation model, and its refusal to provide states the opportunity to opt out of the participation model.

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FERC Ends Notices of Alleged Violations
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Gens Back PJM Pricing Proposal; Md., IMM Oppose

By Rich Heidorn Jr.

PJM utilities and independent power producers joined wind, solar and nuclear generators in support of the RTO's controversial price formation proposal, with some commenters urging it to go further and one saying the plan should be an "off ramp" from the capacity market (ER19-1486, EL19-58).

But Maryland regulators and the Independent Market Monitor asked FERC to reject the proposal, saying it would add billions in costs for negligible benefit.

PJM filed its *proposal* unilaterally in March after a yearlong discussion with stakeholders produced no consensus. The RTO said its plan borrows concepts used by other RTOs to capture the real-time actions of grid operators, including a revised operating reserve demand curve (ORDC); improved utilization of existing capability for locational reserve needs; alignment of the day-ahead and real-time markets; and increased penalty factors. (See *PJM Files Energy Price Formation Plan*.)

PJM's plan received backing in comments by Exelon; FirstEnergy; Duke Energy; the PJM Power Providers Group (including Calpine, NRG Energy and Talen Energy); the Nuclear Energy Institute; the American Wind Energy Association; the Solar Energy Industries Association, and eight energy trading firms.

'Pulling Back the Curtain'

Exelon cited an affidavit by PJM dispatch director Christopher Pilong, which it said "pulls back the curtain of the PJM control room and provides new, conclusive evidence" that operators are using out-of-market actions to commit

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Ex-Coal Plant Site Chosen for Mass. OSW Hub

Brayton Point before the demolition of the cooling towers (p.13) | *Commercial Development Co.*

Abundance of Capacity Ahead of Summer — Except in Texas

By Michael Brooks

WASHINGTON — By now, ERCOT's low reserve margin heading into this summer has been a much-discussed topic.

The grid operator anticipates its reserve margin will be 8.5%, well below its 13.75% target, indicating a possibility it will need to issue an energy emergency alert at some point this

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In this week's issue

Corrections

An *article* in last week's *RTO Insider* transposed the dates of two hurricanes that hit the Carolinas. Hurricane Irma was in 2017 and Hurricane Florence was in 2018.

An *article* in the Dec. 26, 2018, *RTO Insider* incorrectly stated that FERC had approved transmission owners' compliance filings regarding the calculation of accumulated deferred income tax balances in nine dockets. The commission actually approved filings in only two of the dockets (EL18-155 and ER18-2319) while ordering additional compliance filings in seven others. The commission acted in the other seven dockets last week (EL18-138, et al.; EL18-159, et al.; EL18-157; EL18-165; EL18-167; EL18-158; and EL18-164). See related story, *FERC Ends Examinations into TO Tax Calculations*, p. 8.

FERC/Federal News

FERC Upholds Storage Order

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But the majority said the Federal Power Act gives FERC clear jurisdiction over storage.

It cited the Supreme Court's 2016 *EPSA* ruling, which upheld FERC's jurisdiction over the participation in RTO markets of DR resources, which are generally located on the distribution system. "The court did not find the commission's authority to be lessened by the location of demand response resources behind the retail customer meter," the commission said.

"We disagree with assertions by petitioners and the dissent that, unless the commission adopts an opt-out, the commission's regulation of the RTO/ISO market participation of distribution-connected and behind-the-meter electric storage resources violates FPA Section 201. We find that the Supreme Court's jurisdictional findings in EPSA regarding wholesale demand response apply with at least as much force to participation in RTO/ISO markets by electric storage resources engaged in wholesale sales in interstate commerce, even where those resources are interconnected on a distribution system or located behind a retail meter."

The majority also rejected assertions that states can dictate whether resources can participate in the RTO markets through conditions on the receipt of retail service. "We acknowledge that states have the authority to include conditions in their own retail distributed energy resource or retail electric storage resource programs that prohibit any participating resources from also selling into the RTO/ISO markets. In that scenario, the owner of a resource has a choice between participating in the retail market or wholesale market. However, states may not take away that choice by broadly prohibiting all retail customers from participating in RTO/ISO markets."

The commissioners said McNamee incorrectly suggested that the commission had required that storage "be permitted to use distribution facilities so that they may access the wholesale market."

"Although Order No. 841 provides that states may not prohibit electric storage resources from participating in wholesale markets, that requirement does not amount to an effective right of access to the distribution system itself. As noted, Order No. 841 does not modify states' authority to regulate the distribution system, including the terms of access, provided that they do not 'aim directly at the RTO/ISO markets.'"

| SDG&E

Participation Model

FERC also rejected AES' request for rehearing over the use of a single participation model for storage.

"While we agree … that the various technologies that qualify as an electric storage resource under the definition that the commission adopted in the final rule may have different operating characteristics and that new electric storage technologies will likely emerge, we continue to find that a single participation model can be designed to be flexible enough to accommodate any type of electric storage resource," it said.

FERC said AES had mischaracterized Order 841 as requiring that storage resources seeking to participate in RTO markets be available to RTOs as dispatchable resources. But the commission said it would change its regulations to clarify that dispatchable storage must be permitted by RTOs to participate in that manner and be eligible to set clearing prices.

RTO Requests

The commission granted SPP's request for clarification, saying RTOs without capacity markets do not have to create such a product to comply with Order 841. "However, to the extent that an RTO/ISO has a resource adequacy construct, the RTO/ISO must demonstrate on compliance that the existing market rules governing its resource adequacy construct provide a means for electric storage resources to participate in that construct if electric storage resources are technically capable of doing so," it said.

It rejected a clarification request by MISO, reiterating that RTOs must allow storage resources the same ability to self-schedule as other market participants.

In response to another MISO request, FERC clarified that the RTO may propose in its compliance filing a requirement that a storage resource submit its forecasted state of charge at the beginning of any market interval in which it intends to participate. "With that said, we make no findings on the proposal that MISO outlines in its request for clarification," it added.

Minimum Size Requirement

FERC rejected the Edison Electric Institute's request for rehearing on Order 841's directive that RTOs establish a minimum size requirement not to exceed 100 kW, saying the threshold "balances the benefits of increased competition with the potential need to update RTO/ISO market clearing software to effectively model and dispatch smaller resources."

It also rejected MISO's request to phase in the minimum size requirement. "We continue to believe that, given the record showing that all RTOs/ISOs are already accommodating the participation of smaller resources in their markets and the commission's willingness to consider requests to increase the minimum size requirement in the future, we are providing the RTOs/ISOs with adequate time to develop the requisite tariff language and update their modeling and dispatch software to comply

FERC/Federal News

with Order No. 841," it said.

Charging Energy

Pacific Gas and Electric asked the commission to acknowledge that states have jurisdiction to determine how power flowing from distribution lines into the storage located behind the customer meter is split between retail consumption and wholesale charging for later discharge into the wholesale markets.

"The sale of energy from the grid that is used to charge electric storage resources for later resale into the energy or ancillary service markets constitutes a sale for resale in interstate commerce," the commission said. "As such, the just and reasonable rate for that wholesale sale of energy used to charge that electric storage resource is the RTO/ISO market's wholesale LMP."

It said CAISO's request for clarification that storage resources participating as transmission resources should not incur transmission charges for charging demand is premature, noting the ISO "has not yet filed a proposal to allow electric storage resources to provide transmission or reliability services."

In response to another issue raised by CAISO, the commission clarified that "the RTO/ISO itself does not need to be the entity that directly meters electric storage resources."

"We also … clarify that an RTO/ISO could require verification from the host distribution utility that it is unable or unwilling to net wholesale demand from retail settlement before the RTO/ISO ceases to settle an electric storage resource's wholesale demand at the wholesale LMP. While Order No. 841 stated that each RTO/ISO must prevent electric storage resources from paying twice for the same charging energy, it did not specify how each RTO/ISO must implement this requirement."

FERC rejected requests to change the compliance deadlines it set in Order 841, insisting "the timeline for compliance and implementation is reasonable." In April, FERC issued deficiency letters to all six jurisdictional RTOs and ISOs over their compliance filings, pressing for definitions, tariff citations and other details. (See *FERC Asks RTOs for more Details on Storage Rules*.)

Reaction

The National Rural Electric Cooperative Association said FERC "side-stepped" the FPA in its jurisdictional ruling.

"The commission has dealt a blow to consumers and dramatically expanded its authority by giving itself the discretion to decide which distributed and behind-the-meter energy storage resources can participate in wholesale electricity markets," NRECA CEO Jim Matheson said in a statement. "In doing so, FERC has undermined the ability of local utilities and regulatory authorities to manage these resources for the benefit of consumers."

Jeff Dennis, general counsel for Advanced Energy Economy, praised the ruling. "We applaud FERC for upholding Order No. 841, recognizing the benefits to consumers and the grid of giving all energy storage resources, including those located on the distribution grid or behind the meter, an opportunity to participate in wholesale markets," he said.

"We also appreciate Chairman [Neil] Chatterjee's focus on FERC's continued efforts to remove the barriers that keep advanced energy technologies from participating in wholesale markets. Energy storage is just one of the technologies that face barriers to entry. We urge FERC to finalize a similar rule to permit aggregations of distributed energy resources to participate in wholesale markets, utilizing the same legally sound approach taken in today's order." ■

FERC/Federal News

FERC Ends Notices of Alleged Violations

By Michael Brooks

WASHINGTON — FERC on Thursday officially rescinded its controversial policy of allowing its Office of Enforcement to publicly disclose its investigations of possible misconduct and their subjects' identities, ending a practice in place since 2011 (*PL10-2-003*).

The commission in 2009 authorized Enforcement to issue a Notice of Alleged Violations (NAV) after the subject of an investigation had the opportunity to respond to the office's preliminary findings. Enforcement issued its first five NAVs on Jan. 25, 2011, four of which dealt with alleged market manipulation in ISO-NE's Day-Ahead Load Response Program.

NAVs, however, were not like indictments: They were issued before Enforcement staff had finished their investigations and reached their conclusions in the case. Prior to 2011, the commission only disclosed the existence of an investigation and its subjects' identities when it approved the issuance of an Order to Show Cause (OSC). NAVs also did not need to be approved by the commission itself; instead, they were issued after approval from the director of enforcement.

FERC said it had "acknowledged the potential risk of reputational harm that might result from the issuance of a NAV but sought to strike a balance between protecting the confidentiality of investigations and promoting the public interest of heightened transparency."

But the commission found that issuing NAVs generated little information for Enforcement's investigations. And since the policy's adoption, the commission found that other sources, such as data provided by RTOs under Order 760, have been more useful.

"Accordingly, the commission finds that the potential adverse consequences that NAVs pose for investigative subjects are no longer justified in light of the limited transparency NAVs have generated and the more effective, alternative means of adding transparency that the commission has developed since the NAV order." These means include providing guidance through orders on settlement agreements, OSCs and orders assessing civil penalties.

At FERC's open meeting Thursday, Commissioner Richard Glick said the policy had been unofficially ended for some time. Indeed, the last time Enforcement issued a NAV was in April 2018, the only one that year. (See *FERC Investigation Shows PSEG Violated PJM Bidding Rules*.) Prior to that, the office on average issued seven to eight per year.

While Glick acknowledged that NAVs had provided limited value, and joined in the unanimous vote to end the practice, he said that "the Office of Enforcement must act aggressively when there is evidence of market manipulation or other malfeasance that could adversely impact our jurisdictional markets, and I intend to review any future proposals affecting Enforcement's role with that in mind."

Asked by reporters after the meeting whether the commission was considering any other changes to Enforcement policies, Chairman Neil Chatterjee declined to comment. ■

FERC holds its open meeting May 16. | © *RTO Insider*

FERC/Federal News

Abundance of Summer Capacity — Except in Texas

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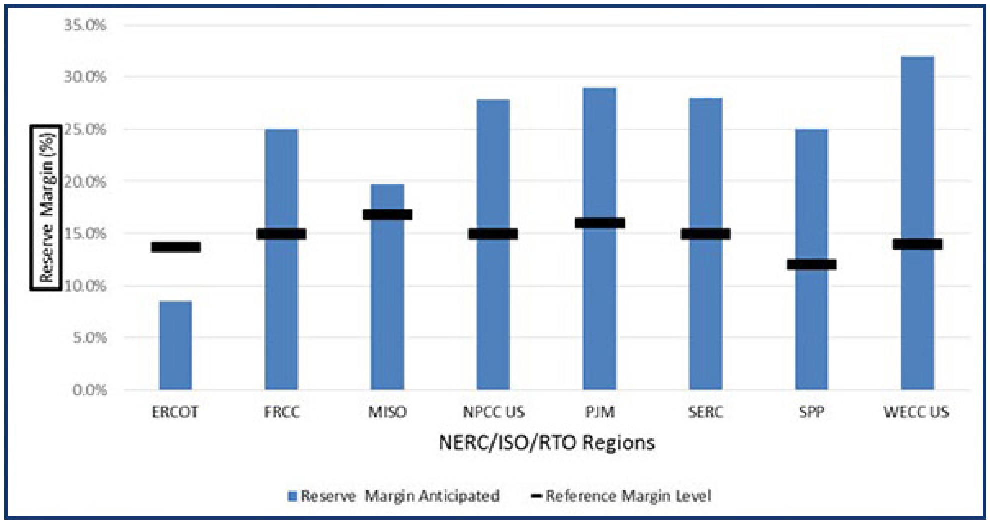
summer. It's forecasting a peak demand of 74.9 GW against 78.9 GW in available capacity. (See *ERCOT: More Capacity, but Emergency Ops Still Expected*.)



Reserve margins are more than adequate in all regions, except ERCOT. | *NERC*

But ERCOT's margin sticks out even more when compared to those of most other regions in the U.S., where their reserves are well above their reference levels. The Western Electricity Coordinating Council region will have reserves of more than 30% against a reference level of slightly less than 15%. PJM comes in second with a margin of slightly less than 30%. Only MISO expects reserves to be only slightly more than its target level.

The reserve margins for this summer were presented to FERC commissioners at their monthly open meeting Thursday as part of staff's annual summer reliability report, using data from NERC's Summer Reliability Assessment, which will be released on May 30, and from the Energy Information Administration.

Last year, FERC was similarly concerned about ERCOT's low reserve margin: 10.92% at the time. But staff noted in their report that the grid operator "maintained system reliability with no load curtailments," and ERCOT has reassured stakeholders repeatedly that it will do so again. (See *FERC Keeps Eye on ERCOT, CAISO as Hot Summer Approaches*.)

FERC is also still concerned about natural gas constraints in California because of low inventories at the Aliso Canyon natural gas storage facility. But "various preliminary assessments have found that the power system is in a better position this summer than during the summer of 2018," staff said. And unlike last year, which saw a decrease in winter precipitation — and therefore less available hydropower — this past winter saw heavy snowfall, with snowpack over 160% of the historical norm as of April 1. (See related story, *CAISO Predicts Plentiful Hydro, Gas Constraints*.)

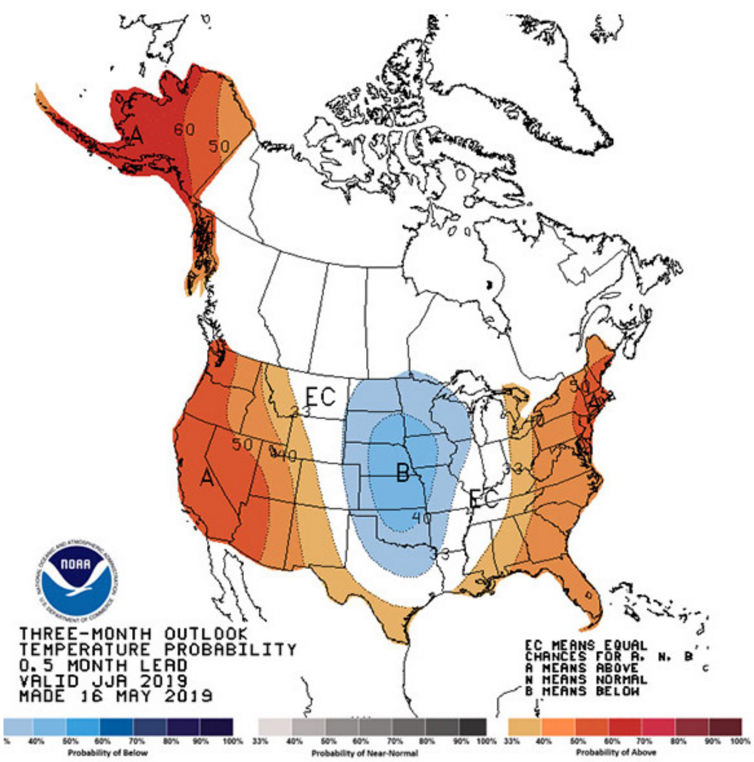
"Preliminary estimates suggest that higher available hydropower plant production this summer will reduce the reliability risk of insufficient operating reserves occurring due to a gas curtailment in California," commission staff said.

Based on EIA data, FERC staff expect net new generation capacity to be about 4.1 GW, with about 6.7 GW to come online against 2.6 GW of retirements. Most of the retirements consist of coal resources (0.8 GW in PJM) and two nuclear plants — one each in ISO-NE and PJM — worth 1.5 GW.

Commissioner Richard Glick noted the high reserve margins in comments after the staff presentation. While he said it was good news that the U.S. doesn't have a resource adequacy problem, the figures suggest that "it's worth taking another look at" the way some regions are procuring capacity. "Because if we're significantly over the targeted reserve margins, something's wrong."

He said he knew that some of the capacity was leftover and no longer receiving payments. "There's also a lot receiving capacity payments; there's not a lot of retirements going on," he said. "We need to figure that out: how we can get closer to the targets."

Asked about potential overcapacity and its costs to consumers, FERC Chairman Neil Chatterjee told reporters after the meeting, "It's something that we'll look at. My takeaway from the report is we're in good shape for the coming summer, but we need to be vigilant regarding discrete issues," particularly ERCOT and gas constraints in the West. ■



Three-month temperature outlook, as of May 16. This projection was coincidentally released the same day FERC staff presented their report, which used NOAA's (mostly similar) projection from April 18. | *NOAA*

FERC/Federal News

FERC Proposes Adopting NAESB Standards

By Rich Heidorn Jr.

NAESB is an industry forum that develops standards for the wholesale and retail natural gas and electricity industries. | *NAESB*

FERC last week proposed adopting the North American Energy Standards Board's (NAESB) Standards for Business Practices and Communication Protocols for Public Utilities, which implement the commission's requirements under the pro forma Open Access Transmission Tariff (*RM05-5-027*).

Version 003.2, approved by NAESB's Wholesale Electric Quadrant, includes changes from WEQ Version 003.1, which were the subject of an earlier FERC Notice of Proposed Rulemaking that was never completed (*RM05-5-025*).

WEQ Version 003.2 also includes changes to make it consistent with NERC reliability standards regarding dynamic tagging and pseudo-ties, and the transition of NERC's electric industry registry tool to NAESB.

The NOPR does not include NAESB's WEQ-023 Modeling Business Practice Standards, which govern the calculation of available transfer capability for transmission, which is the subject of a separate rulemaking (*RM05-5-025*). It also has issued a separate NOPR proposing the retirement of the WEQ-006 Time Error Correction Business Practice Standards (*RM05-5-026*).

The commission also declined to incorporate into its regulations the Standards of Conduct for Electric Transmission Providers (WEQ-009); Contracts Related Standards (WEQ-010); and WEQ/WGQ eTariff Related Standards (WEQ-014).

NAESB's voluntary standards become mandatory for FERC-regulated public utilities after they are incorporated into the commission's regulations.

Redirects

FERC said it would not incorporate the preamble to WEQ 001-9 "because it leaves the implication that a transmission operator could adopt a 'transmission provider-specific business practice' that is at odds with the reason for establishing common business practices standards under the NAESB standards development process."

The commission's 2002 Dynegy decision set its policy on a customer's right to keep the contractual rights to firm transmission service it had reserved while the customer's request for a redirect was pending (*EL01-104*).

The commission said a transmission customer submitting a redirect request does not lose its rights to its original path until the redirect request is accepted by the transmission provider, confirmed by the transmission customer and passes the conditional reservation deadline under the transmission provider's OATT.

In declining to adopt the preamble, the commission rejected arguments by the Edison Electric Institute, Public Utility District No. 1 of Snohomish County, Wash., and the city of Tacoma, Wash.'s Department of Public Utilities that the commission should allow redirects from a conditional parent reservation on a case-by-case basis, calling it "antithetical to the NAESB standards development process." ■

FERC/Federal News

FERC Approves Expansion to Freeport LNG Export Terminal

By Michael Brooks

WASHINGTON — FERC voted 3-1 on Thursday to approve the construction of a fourth liquefaction unit at the Freeport LNG export terminal in Brazoria County, Texas (*CP17-470*).

The unit, called a "train" in the LNG industry, will allow for the export of an additional 5.1 million metric tons per annum (mtpa), equivalent to about 0.74 Bcfd. Currently, the facility has a capacity of 15.49 mtpa (2.14 Bcfd), according to FERC.

The approval of the so-called Train 4 Project marks FERC's fourth approval of an LNG project this year, following last month's approval of the Driftwood and Port Arthur projects, and February's approval of the Venture Global Calcasieu Pass project. And as has become common, the order elicited celebration from Chairman Neil Chatterjee, a reluctant concurrence from Commissioner Cheryl LaFleur and a dissent from Commissioner Richard Glick over the commission's reticence to assess the project's impacts on global climate change.

"I'm proud of the efforts by the commission and its staff to process today's and our previous LNG orders," Chatterjee said in a *statement*. "Exporting LNG from the United States can help increase the availability of inexpensive, clean-burning fuel to our global allies who are looking for an efficient, affordable and environmentally friendly source of generation."

FERC disclosed in its order that its environmental assessment (EA) of Train 4 estimated that operation of the project may result in emissions of up to 491,500 metric tons per year of carbon dioxide equivalent, increasing national emissions by about 0.01%. "Currently, there are no national targets to use as benchmarks for comparison," the commission said.

This was enough to secure LaFleur's vote, though she warned that the order, as with previous LNG approvals, are vulnerable to judicial scrutiny. She also noted that an additional risk existed for Train 4 because the commission issued an EA instead of an environmental impact statement (EIS). Under the National Environmental Policy Act, federal agencies issue an EIS when they find that an action will have a significant impact on the environment.

"This tension between the finding of no significant impact, and the commission's failure to assess significance of climate change impacts, heightens the risk that a court could vacate and remand this project, simply on the basis of which environmental document was prepared," LaFleur said in her concurrence.

At Thursday's meeting, Glick noted that Chatterjee has said that the Natural Gas Act doesn't give the commission authority to analyze the impact of natural gas infrastructure on climate change. He then turned and appealed directly to Chatterjee, suggesting that they "work together to send some draft legislation to Congress to fix the problem and clarify that FERC does have such authority."

Asked by reporters about Glick's remarks after the meeting, Chatterjee dismissed the idea, saying "there is a 0% chance that such legislation could get through the United States Senate. We have so many things to focus on, that to me is not a worthwhile thing to spend time on."

Commissioner Bernard McNamee said the approval was "another great achievement." He emphasized "that we have considered all the environmental effects, including greenhouse gases. I know there's a disagreement about ... how those should be measured. ... But a disagreement about that does not mean they were not considered." ■

Freeport LNG export terminal | *Freeport LNG Development*

CAISO/WECC News

Cal Fire Pins Deadly Camp Fire on PG&E

By Hudson Sangree

Pacific Gas and Electric transmission and distribution lines caused the deadliest and most destructive fire in California history, state fire officials announced Wednesday.

The Camp Fire in rural Butte County flared the morning of Nov. 8 near the tiny community of Pulga. Within hours it killed at least 85 people, destroyed 18,804 structures and burned more than 153,000 acres. The fire destroyed the town of Paradise, population 27,000.

Investigators with the California Department of Forestry and Fire Protection (Cal Fire) said the fire's main origin was beneath a PG&E transmission tower on the 100-year-old Caribou-Palermo line.

The department said in a *statement* that it made the determination "after a very meticulous and thorough investigation."

A second ignition occurred nearby when vegetation contacted a PG&E distribution line, Cal Fire said. That second fire was consumed by the main blaze.

"The tinder dry vegetation and red flag conditions consisting of strong winds, low humidity and warm temperatures promoted this fire and caused extreme rates of spread, rapidly burning into Pulga to the east and west into Concow, Paradise, Magalia and the outskirts of east Chico."

Cal Fire said it forwarded the results of the investigation to the Butte County district attorney for possible criminal investigation.

The announcement that PG&E started the fire was long awaited but not a surprise. The utility has already said its equipment most likely started the blaze.

"The act by Cal Fire of forwarding its report is strictly symbolic," Butte County District Attorney Mike Ramsey's office said in a statement Wednesday. "The fact the Camp Fire was started by a malfunction of equipment on a Pacific Gas and Electric Co. transmission line has been known for months by investigators and had been, essentially, admitted by Pacific Gas and Electric in an early December 2018 report to the California Public [Utilities] Commission."

Ramsey said his office would provide no further comment on its investigation, "which is expected to last from weeks to months."

National Guard soldiers search through rubble in November after the Camp Fire tore through Paradise, Calif., killing 85 and casting suspicion on PG&E. | *California National Guard*

The expected liability from the Camp Fire — currently estimated by PG&E to be about $14 billion — was a major reason the utility filed for bankruptcy in January. (See *PG&E Wants to Undo Contracts, Revamp Biz in Bankruptcy*.)

Cal Fire has also blamed PG&E for 18 of 21 major wildfires in 2017 that burned through Northern California wine country and the Sierra Nevada foothills.

All told, PG&E said it is facing more than $30 billion in liability for the 2017 and 2018 blazes.

'Wrong Message'

California Gov. Gavin Newsom last month released a report criticizing PG&E for its lax safety standards and accusing the utility of "taking advantage of the bankruptcy process to promote the interests of investors over fire victims and other stakeholders." (See *Calif. Must Limit Wildfire Liability, Governor Says*.)

The report said the state should monitor and intervene in the bankruptcy to protect California residents and keep open the option of breaking up the utility.

Acting in that vein, Newsom's office on Wednesday asked the judge overseeing PG&E's bankruptcy to deny the utility's request for a six-month extension of its "exclusivity period" for producing a reorganization plan, urging the court to instead grant a 75-day extension at the most.

Under U.S. bankruptcy law, debtors normally have 120 days from the date of a bankruptcy filing in which to file a reorganization plan. Parties wanting to file a competing plan during that time must convince the judge to terminate the exclusivity period.

In a brief submitted to the U.S. Bankruptcy Court in San Francisco, Newsom said PG&E's request "reflects no sense of urgency in addressing the serious problems and issues confronting" the company.

"The requested six-month extension is of particular concern because it encompasses the entirety of the 2019 wildfire season, thereby exposing PG&E to the risk of unquantifiable post-petition claims arising from 2019 wildfires," Newsom wrote. "Such a prolonged extension of exclusivity to file a plan of reorganization would send PG&E and all of its stakeholders the wrong message. Allowing PG&E to continue a business-as-usual approach without any accountability would only encourage PG&E's distressed investors to leverage the Chapter 11 cases to their benefit and to the detriment of existing and future wildfire victims."

Newsom reminded Bankruptcy Judge Dennis Montali that PG&E entered bankruptcy as a convicted felon over its culpability for and obstruction of justice related to the 2010 San Bruno natural gas pipeline explosion.

"Nor should we ignore the reality that victims of the catastrophic fires in 2017 and 2018 suffered unimaginable losses and are still struggling to rebuild their lives," Newsom said. "Allowing PG&E to remain in Chapter 11 without accountability will only unfairly cast doubt and uncertainty over the recovery on victims' claims and prepetition settlement obligations." ■

Robert Mullin contributed to this article.

CAISO/WECC News

Turlock Irrigation District to Join Western EIM

By Robert Mullin

Turlock Irrigation District operates the 203-MW Don Pedro Dam in partnership with Modesto Irrigation District. | *Turlock Irrigation District*

California's oldest irrigation district has become the latest balancing authority to commit to the Western Energy Imbalance Market.

CAISO said Wednesday that Turlock Irrigation District (TID) signed an agreement to join the EIM in April 2021, putting it on track to begin trading alongside Los Angeles Department of Water and Power, NorthWestern Energy and Public Service Company of New Mexico.

TID's decision comes just a week after Arizona-based Tucson Electric Power said it will link up with the real-time market in 2022. (See *Tucson Electric Power Signs up for Western EIM*.)

Established in 1887 to provide water to farmers in California's Central Valley, TID now serves more than 100,000 electricity accounts in addition to 5,800 irrigation customers. The district's generation portfolio includes 137 MW of wind, 98 MW of natural gas, 54 MW of contracted solar, a small amount of geothermal and a 68% share of the output from the 203-MW Don Pedro hydroelectric dam.

TID also owns a share of the California-Oregon Intertie, the key link between the Pacific Northwest and Northern California. Its transmission network interconnects with neighboring systems operated by CAISO, the Western Area Power Administration, the California-Oregon Transmission Project and the Sacramento Municipal Utility District (SMUD), the last of which began transacting in the EIM last month.

"TID's participation in the Energy Imbalance Market will lead to a greater utilization of our resource portfolio," Brad Koehn, the district's assistant general manager of power supply, said in a statement. "Additionally, gaining access to the resource diversity within the EIM footprint will help us maintain our core mission of providing reliable and affordable power."

The sheer momentum of the EIM — combined with a parallel decline in regional bilateral markets — appears to have sealed the deal for TID.

"With the amount of utilities participating in the intra-hour market, TID expects the hourly markets it currently participates in will become much less liquid compared to previous years. Over time, this reduced liquidity would likely lead to increased purchased power and fuel costs, absent participation in the EIM," TID *said* last month in announcing its plans.

TID estimates it will recoup its $5.5 million in EIM start-up costs in two to three years.

The EIM's current members in addition to SMUD are Arizona Public Service, Idaho Power, NV Energy, PacifiCorp, Portland General Electric, Puget Sound Energy and Powerex. CAISO last month said the EIM has yielded $650.26 million in benefits for its members since being launched with PacifiCorp as its first member in November 2014. ■

CAISO Predicts Plentiful Summer Hydro, Gas Constraints

ISO Board Approves BTM Reporting Rules

By Hudson Sangree

CAISO's summer load forecast predicts an abundance of hydroelectric power but constraints on natural gas supplies, the ISO's Board of Governors heard Wednesday.

As of April 1, California snowpack is over 160% of normal this year, Bob Emmert, the ISO's manager of interconnection resources, told the governors. That's far different from last year, when it was 51% of normal, he said.

"This year we have a pretty robust snowpack condition," Emmert said.

That means there may be an excess of runoff in the spring but snowmelt will continue well into the summer to power hydroelectric plants, he said.

The picture isn't entirely rosy, however.

There's been a 2,061-MW reduction in dispatchable resources because of retirements and mothballing of natural gas plants, he said. That could be a problem when demand remains high after solar power fades in the evening.

Almost all the low operating margin conditions in CAISO's models occur during minimal or zero solar output, he said. ISO staff run 2,000 scenarios to project summer load and possible problems. The computers take several days to complete the task, Emmert said.

Continuing problems at the Aliso Canyon natural gas storage facility in Southern California could add to the inability of resources to meet peak summer demand, Emmert said. That could prove especially troubling for local reliability in Southern California, he said.

Reporting Rules for Excess BTM

The board also approved a measure standardizing how load-serving entities report load values to the ISO in the face of proliferating behind-the-meter generation.

In pushing for the measure, staff pointed to the inconsistency of some LSEs reporting their customers' "net load" (energy transmitted through the retail meter minus any metered energy exported back to the grid) and others reporting "gross load" (the amount of energy customers consume directly from the grid net of any energy consumed from BTM output).

"Reported load values are key inputs to many of the ISO's settlement calculations," CAISO management said in a *memo* to the board.

In that memo, CAISO explained that "excess" BTM production — which represents the amount of energy exported to the grid when a customer's BTM generation exceeds its on-site load — should not be included in gross load figures sought by the ISO.

The new measure would clarify Tariff language to ensure consistent reporting of gross load and specify that scheduling coordinators do not net excess BTM production from the gross load figures reported to CAISO. The measure would also add a Tariff definition for excess BTM production and require that LSEs report it to the ISO.

"Currently, the magnitude of this problem is relatively small, but as the grid continues to increase adoption of behind-the-meter solar resources, the impact of these inconsistencies and reporting problems will grow," the ISO said.

California last year passed a law requiring all new construction to include rooftop solar beginning in 2020.

'Charging Hard'

In his update to the board, CEO Steve Berberich said CAISO is "charging hard" toward the July 1 launch of RC West, the ISO's new reliability coordination service that will operate in much of the West after Peak Reliability winds down operations later this year. (See *CAISO RC Wins Most of the West*.) The staggered rollout begins with California and northern Mexico and expands to balancing authority areas in other states in November after two months of shadow operations.

Berberich also said the ISO experienced a record solar output of 11,350 MW in May along with a record wind output of 5,309 MW, moving California closer to achieving its ambitious green energy goals. ■

Robert Mullin contributed to this article.

CAISO expects the winter's abundant Sierra Nevada snowpack to keep hydroelectric output strong into summer. | *U.S. Bureau of Reclamation*

TRE Board of Directors Briefs

New Processes Add Efficiency, Effectiveness

Stressing the importance of being efficient and effective, the Texas Reliability Entity's Derrick Davis last week shared with his Board of Directors a new process to help the regional entity devote more time to its ERO responsibilities.

"I'm going to say more efficient and more effective 1,000 times," said Davis, director of enforcement, reliability standards and registration, during the board's Wednesday meeting.

Davis told the board that the RE's new mitigation verification sampling process will be, of course, "more efficient and more effective" in resolving smaller issues, freeing up staff to perform other tasks.

TRE staff will verify mitigation for compliance exceptions on a sample basis. Registered entities will be required to provide an affidavit identifying the details of mitigation activities and source documents. Entities will hold the mitigating evidence for 18 months after being notified of compliance exception treatment or upon completion of mitigation activities, whichever is later.

Staff have also begun using a new triage process to obtain disposition information faster. Davis said enforcement staff will ask for "pertinent disposition information" earlier in the process than before, leading to quicker validations.

"In the past, we haven't had an answer for an entity that self-reports and waits for the enforcement group to get with them," he said. "We're going to get to you faster now, so that we can close these out."

2020 Risk Elements Focus on Resource Adequacy

Staff have proposed three regional risk elements to focus on for 2020: data integrity and situational awareness; resource adequacy; and insufficient dynamic performance and loadability by transmission and generation providers.

Risk Assessment Manager Jeff Hargis told directors that risk elements are translated into audit scopes. These specific, defined risks are determined on an annual basis, he said.

"We live in the future," Hargis said.

He said the resource adequacy risk is not a result of ERCOT's slim summer reserve margins, but whether or not resources adequately support frequency and voltage and stay online during transient events. Multiple resource failures can lead to system instability or a significant loss of generation, Hargis said.

Texas Tops Other REs in Effectiveness Survey

COO Jim Albright told directors that TRE bested all other REs on NERC's 2018 ERO effectiveness survey. The Texas RE registered an average score of 3.91, based on a 5-point scale; the Florida Reliability Coordinating Council came in second, with an average score of 3.88.

TRE received its highest score (4.23) for its business planning and budgeting process, which stakeholders found provide reasonable opportunities for input and offer sufficient information, Albright said. It was also rated highly for its audit reports and audit process (4.19 and 4.14, respectively) and for enforcement (4.13).

The organization fared poorest in enforcement and standards, with no score higher than 3.77. Still, it was rated highest among the regions for its regional reliability standards addressing risk in a cost-effective manner.

Respondents favorably commented on the "competent" compliance monitoring and enforcement staff and found the organization's self-certification process to be an "effective engagement method." However, they dinged TRE for a lack of transparency and consistency on the penalty and internal risk assessment processes.

"When you look at the number of penalties we actually had, it's a small number," Albright said, noting TRE has only assessed "six or seven" penalties in recent years. "The opportunities to be transparent are few and far between."

The ERO effectiveness survey, composed of 76 questions across five topic areas, is conducted every two years. TRE received 92 responses in 2018, up from the 54 it received in 2016. It has 222 entities registered in its region.

"We're reaching more people, which is a good thing," Albright said.

He also said TRE's certification process has received a clean report from NERC.

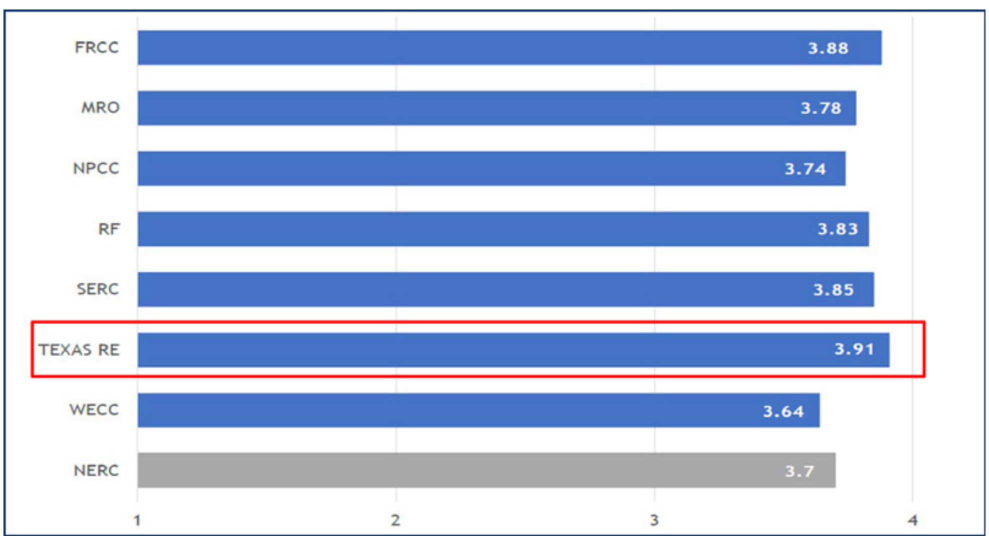
Board Approves 2018 Budget, Audit

The directors approved the RE's 2020 business plan and budget of $13.8 million, a 5.8% increase over the current budget. The approval is subject to "no material changes," as NERC has not completed its review of the budget.

The Member Representatives Committee approved the budget May 3.

The board also approved accounting and advisory firm BKD's 2018 financial audit report, which had no reported findings, and accepted its financial statements for the same year. ■

— Tom Kleckner



2018 ERO effectiveness survey: overall averages by region | *Texas RE*

Ex-Coal Plant Site Chosen for $650M Mass. OSW Hub

By Rich Heidorn Jr.

In an announcement rich with symbolism, transmission developer Anbaric said it will spend $650 million to build a delivery hub for offshore wind at Brayton Point, the former site of New England's largest coal-fired plant.

Anbaric said it will spend $250 million on a 1,200-MW high-voltage direct current (HVDC) converter to receive offshore wind power and another $400 million on 400 MW of battery storage at what it is calling the Anbaric Renewable Energy Center. The May 13 announcement by Anbaric and Commercial Development Co., the owner of the 307-acre site in Somerset, Mass., came just days after the former coal plant's 500-foot cooling towers were *imploded*.

Terms of the lease between the two companies were not released, but CDC Executive Vice President Stephen Collins said the lease is "very long."

Anbaric CEO Edward Krapels *said* the project is part of his company's plan for its Massachusetts *OceanGrid* to bring wind power from projects off southeastern Massachusetts, Cape Cod, Nantucket and Martha's Vineyard to ISO-NE.

Stephen Conant, an Anbaric partner and project manager for the Brayton Point project, said construction could begin as early as 2021, depending on how soon Anbaric signs up generation to use the facilities.

Anbaric is counting in part on Massachusetts' 2016 directive ordering Eversource, National Grid and Unitil to procure 1,600 MW of offshore wind.

Conant said his company will partner with an unnamed generator to bid for an 800-MW OSW solicitation the utilities are expected to issue later this month. But he said Anbaric is "open to working with any and all" OSW generators, including those off of Rhode Island and Connecticut.

"It's a very attractive site," he said, noting the 1,600-MW interconnection from the old coal plant. "It's the best interconnection facility on the south coast" of Massachusetts.

Anbaric *filed* a 1,200-MW interconnection request with ISO-NE in March, and Conant said the company could seek to increase that to 2,400 MW with upgrades.

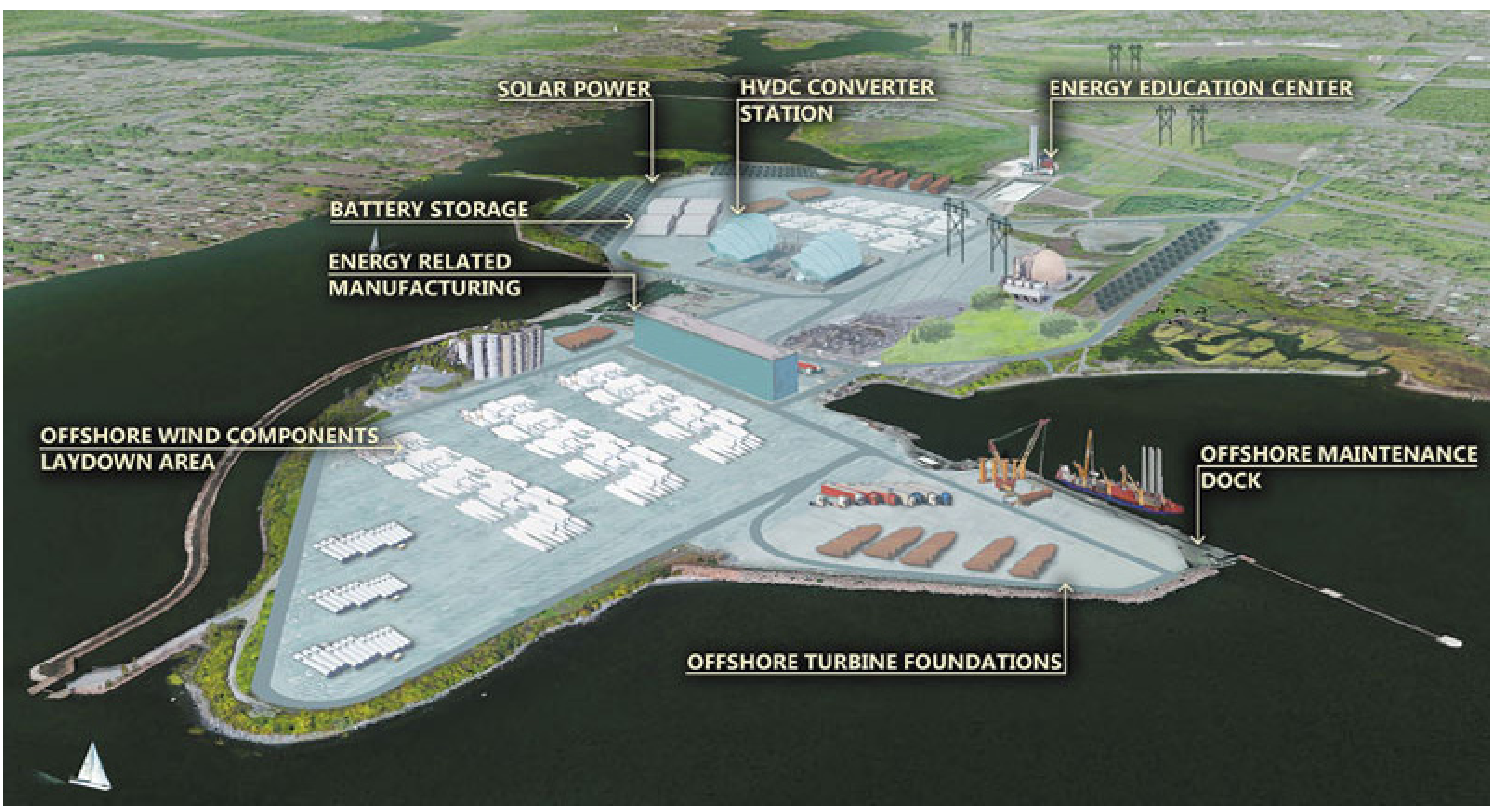
The company received FERC approval in February 2018 to conduct an "open season" bidding process for OSW developers to use its Massachusetts OceanGrid to deliver OSW power to ISO-NE (*ER18-435*).

Anbaric said it expects its project to create 300-400 construction jobs over a two-year period, with five to 10 full-time employees running the center once completed.

"It's certainly not going to replace the number of jobs lost at the coal plant," which employed about 250, Conant acknowledged. But he said the "real jobs are going to come from the growth of offshore wind … and well-developed infrastructure will make that happen."

Conn. Adding 2,000 MW?

Connecticut and Rhode Island have agreed to purchase 700 MW of OSW from Eversource's and Ørsted's Revolution Wind project be-



Artist's depiction shows Anbaric's planned HVDC and battery storage project and other potential offshore wind facilities, including space for storing turbine components on land that was once covered with coal piles. | *Anbaric*

ISO-NE News

tween Martha's Vineyard and Block Island.

In addition, the Connecticut House on May 14 approved *legislation* that would authorize Eversource and Avangrid subsidiary United Illuminating to procure an additional 2,000 MW of offshore wind. The bill, which is headed to the state Senate, calls for the issuance of a solicitation within two weeks of passage to take advantage of expiring federal tax credits, Conant said.

But Connecticut officials have their own plans for capitalizing on their procurements, earlier this month *announcing* agreement on a $93 million public-private partnership to make State Pier in New London an OSW hub.

Other Tenants?

Anbaric's project will take only 20 acres of the former power plant's 300-acre site, which CDC has renamed *Brayton Point Commerce Center*.

Collins said the company is "actively engaged" with about a half-dozen additional potential tenants interested in the site and its 34-foot deep port, some of them also in offshore wind or energy. "There's an enormous amount of interest at this site," he said. "I've had five meetings in the last two days."

Bay State Wind *announced* a year ago it would

U.S. Rep. Joseph Kennedy III (D-Mass) spoke at an announcement of the Anbaric lease. | *Joseph Kennedy III*

build turbine foundations at the site if it won Massachusetts' first 800-MW OSW solicitation, but that contract was snagged by Vineyard Wind. Collins said Vineyard Wind has talked about bringing work on the "transition piece" between the turbines' monopole and nacelle to Brayton Point.

Anbaric has partnered with Vineyard on the Liberty Wind project in New York but was not part of its initial Massachusetts bid.

CDC purchased Brayton Point from Dynegy in early 2018 after the 1,600-MW plant, Massachusetts' last coal generator, shut down in May 2017 after more than 50 years of operation.

Before imploding the cooling towers last month, CDC had sold much of the plant's equipment and machinery, begun demolishing fuel oil tanks and power plant buildings and conducted asbestos abatement and other environmental remediation. ■


Brayton Point before the demolition of the cooling towers | *Commercial Development Co.*

ISO-NE News

Eversource Balks at ISO-NE Plan on CIP Costs

By Rich Heidorn Jr.

ISO-NE on Thursday proposed a “hybrid” filing Section 205 of the Federal Power Act to allow some generators to recover the costs of NERC critical infrastructure protection (CIP) requirements, but Eversource Energy suggested alternatives, saying it doesn’t want the costs collected as part of its transmission rates.

The RTO’s Jonathan Lowell made the proposal at a meeting of the New England Power Pool’s Transmission Committee on Thursday. It would allow cost recovery for generators designated by the RTO as “critical” to the determination of interconnection reliability operating limits (IROLs), which have higher CIP standards than other generators.

Violations of IROLs can lead to instability, uncontrolled separation and outages cascading into neighboring regions. Generators are designated as IROL-critical because of their characteristics and locations relative to other control areas, the RTO said.

ISO-NE says it has about as many IROLs as all other ISOs and RTOs together. “Because New England is at the eastern end of the Eastern Interconnection, a contingency in New England can have significant reliability impacts on systems to the west,” explained ISO-NE spokeswoman Marcia Blomberg. “Many interconnection reliability operating limits have been identified in New England to avoid creating those impacts, and many facilities have been determined to be critical to the determination of those limits.”

The RTO is proposing to make a Section 205 filing with FERC to add a new OATT Schedule 17 for the billing and collection of FERC-approved IROL-CIP costs, with the RTO serving as billing agent. It would be based on a formula rate template listing recurring and nonrecurring costs.

The initial filing will “facilitate a smooth and efficient FERC review of the Section 205 formula rate filing by having resolved most controversies in advance,” the RTO said in a *presentation*.

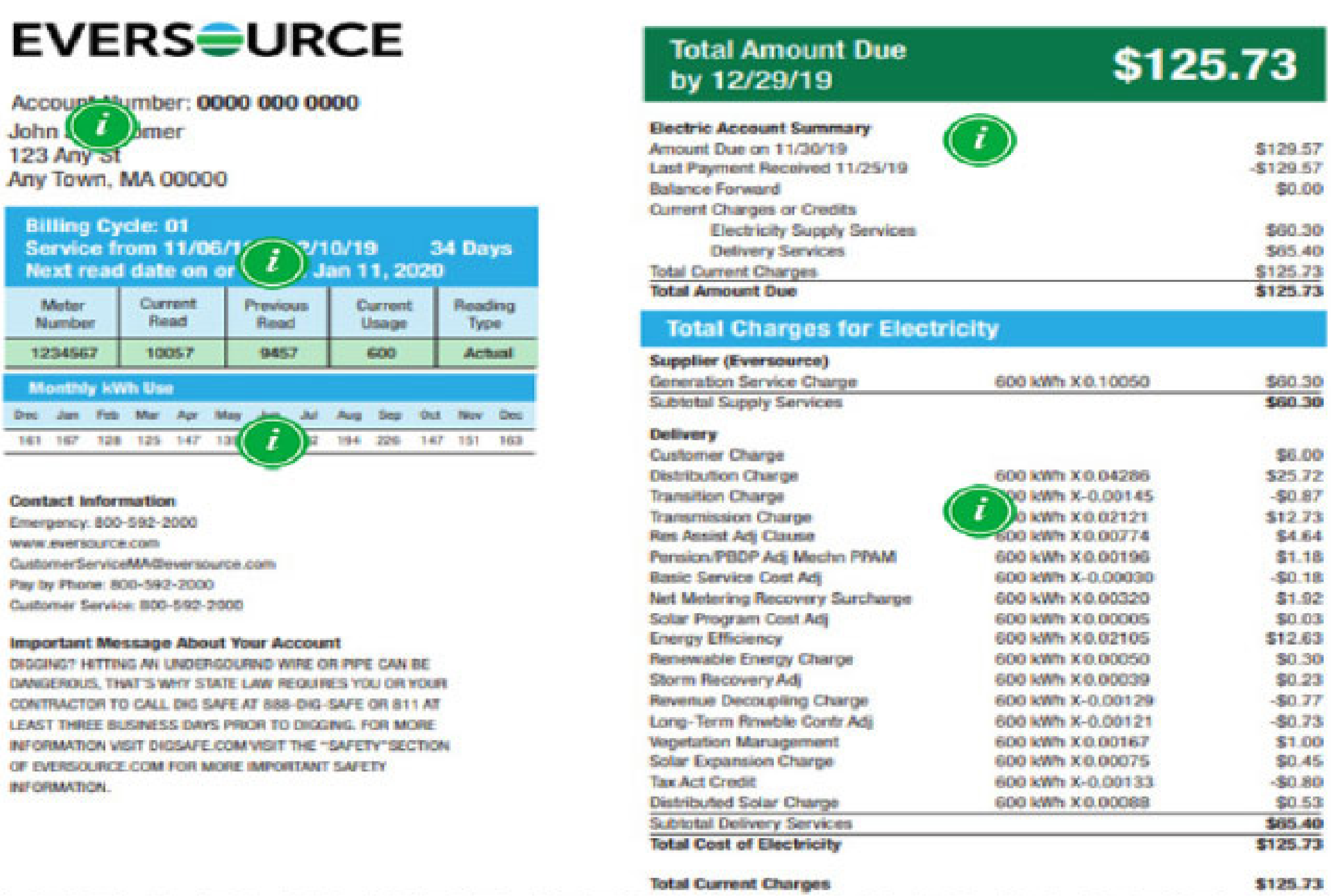
Critical generators and similarly situated transmission facilities would then make their own Section 205 filings itemizing their costs for FERC review and approval.

ISO-NE said the two-step filing is necessary because the RTO cannot be responsible for supporting the costs of individual facilities.

‘Inappropriate’

But Cal Bowie, representing Eversource, told the committee in a *presentation* that it is “inappropriate” for generators to recover expenses through regional network load transmission charges. “Transmission charges should pri-

Continued on page 18



EVERSOURCE

Account Number: 0000 000 0000
John Customer
123 Any St
Any Town, MA 00000

Billing Cycle: 01
Service from 11/06/19 to 12/10/19 34 Days
Next read date on or about Jan 11, 2020

Meter Number	Current Read	Previous Read	Current Usage	Reading Type
1234567	10057	9457	600	Actual

Monthly kWh Use

Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
161	167	128	125	147	13[illegible]	[illegible]	[illegible]	194	226	147	151	163

Contact Information
Emergency: 800-592-2000
www.eversource.com
CustomerServiceMA@eversource.com
Pay by Phone: 800-592-2000
Customer Service: 800-592-2000

Important Message About Your Account
DIGGING? HITTING AN UNDERGOURND WIRE OR PIPE CAN BE DANGEROUS. THAT'S WHY STATE LAW REQUIRES YOU OR YOUR CONTRACTOR TO CALL DIG SAFE AT 888-DIG-SAFE OR 811 AT LEAST THREE BUSINESS DAYS PRIOR TO DIGGING. FOR MORE INFORMATION VISIT DIGSAFE.COM VISIT THE "SAFETY" SECTION OF EVERSOURCE.COM FOR MORE IMPORTANT SAFETY INFORMATION.

Total Amount Due by 12/29/19 $125.73

Electric Account Summary	
Amount Due on 11/30/19	$129.57
Last Payment Received 11/25/19	-$129.57
Balance Forward	$0.00
Current Charges or Credits	
Electricity Supply Services	$60.30
Delivery Services	$65.40
Total Current Charges	$125.73
Total Amount Due	**$125.73**

Total Charges for Electricity

Supplier (Eversource)		
Generation Service Charge	600 kWh X 0.10050	$60.30
Subtotal Supply Services		**$60.30**
Delivery		
Customer Charge		$6.00
Distribution Charge	600 kWh X 0.04286	$25.72
Transition Charge	600 kWh X -0.00145	-$0.87
Transmission Charge	600 kWh X 0.02121	$12.73
Res Assist Adj Clause	600 kWh X 0.00774	$4.64
Pension/PBOP Adj Mechn PPAM	600 kWh X 0.00196	$1.18
Basic Service Cost Adj	600 kWh X -0.00030	-$0.18
Net Metering Recovery Surcharge	600 kWh X 0.00320	$1.92
Solar Program Cost Adj	600 kWh X 0.00005	$0.03
Energy Efficiency	600 kWh X 0.02105	$12.63
Renewable Energy Charge	600 kWh X 0.00050	$0.30
Storm Recovery Adj	600 kWh X 0.00039	$0.23
Revenue Decoupling Charge	600 kWh X -0.00129	-$0.77
Long-Term Rnwble Contr Adj	600 kWh X -0.00121	-$0.73
Vegetation Management	600 kWh X 0.00167	$1.00
Solar Expansion Charge	600 kWh X 0.00075	$0.45
Tax Act Credit	600 kWh X -0.00133	-$0.80
Distributed Solar Charge	600 kWh X 0.00088	$0.53
Subtotal Delivery Services		**$65.40**
Total Cost of Electricity		**$125.73**
Total Current Charges		**$125.73**

Eversource Energy told the NEPOOL Transmission Committee that the costs of generators’ compliance with NERC CIP requirements should not be recovered in transmission rates. | *Eversource Energy*

ISO-NE News

NEECE Panelists Discuss Public Policy Drivers

By Michael Kuser

Left to right: Marc Montalvo, Daymark Energy Advisors; Katie Dykes, Connecticut DEEP; Theodore Paradise, Anbaric; Rita King, Avangrid; and David Ismay, Conservation Law Foundation. | © *RTO Insider*

GROTON, Conn. — As Northeast states continue to expand their clean energy goals, the region faces the prospect that multiple overlapping public policies will create an oversupply of renewable resources at certain periods.

Katie Dykes | © *RTO Insider*

"We're very soon, even with the contracts we have in place, going to be in a position where our supply of contracted resources is going to exceed demand in some hours," Katie Dykes, commissioner of the Connecticut Department of Energy and Environmental Protection (DEEP), said Wednesday at the 2019 New England Energy Conference and Exposition, hosted by the Connecticut Power and Energy Society and the Northeast Energy and Commerce Association.

Dykes noted that the Connecticut House of Representatives had a day earlier approved legislation (*H.B. 7156*) that would authorize DEEP to procure up to 2,000 MW of offshore wind resources over the next decade, "with a real focus on looking at a solicitation to be issued as soon as possible after the ink is dry on the governor's signature."

"It's really an exciting time, [and] the question society has to be focusing on in the integrated resource planning process in Connecticut is how are we meeting resource adequacy with the public policy resources," Dykes said. "We have to think about when we're buying zero-carbon resources that are just displacing other contracted resources in certain hours, those benefits aren't going to materialize in terms of meeting the carbon goals ... and be reflecting that in our procurements."

Michelle Morin | © *RTO Insider*

Many stakeholders are not that familiar with the technical aspects of offshore wind, so it's important to have someone who can bridge that knowledge gap, said Michelle Morin, chief of the environment branch in the U.S. Bureau of Ocean Energy Management's Office of Renewable Energy Programs.

"For example — the [OSW transmission] cable landfall. I get a lot of concerns that [it] will industrialize an area, so showing people what that will look like goes a long way," Morin said.

Marc Montalvo | © *RTO Insider*

The region's switch from fossil fuels to wind, solar and storage is being driven by customer demand for cleaner energy, falling costs of new technologies and public policy, said Marc Montalvo, president of Daymark Energy Advisors.

"And the policy interests have many dimensions, like protecting the environment, building strong neighborhoods and communities, making sure the economy is robust," Montalvo said. "It's really interesting that we're talking now about harmonizing markets and public policy, when the wholesale markets that we have in the region, and the way they're organized, are themselves a response to public policy."

Out of Market

Theodore Paradise | © *RTO Insider*

Markets are very product-specific, and until recently the social science of economics was treated almost like a hard science, which created pejorative assumptions about what constitutes out-of-market actions or mechanisms, said Theodore Paradise, counsel and senior vice president for transmission developer Anbaric.

"Certain orders of market constructs have been protected because people thought that's what they should do," Paradise said. "But I think, again, not in 2030 but now, that we're at the end of that paradigm. At this point, buyers are being told they can't purchase what they want.

"And this is the proof that the bigger buyers and sellers that are outside this smaller market are really a market, because what do buyers do in a market when they're being told you can't buy that?" he said. "They go buy it elsewhere, and that's what has happened."

Paradise said the region has arrived at the point where buyers are making direct contracts for resources.

"It's being conducted in a space that's not out-of-market; it's just a different market," he said.

In addition to competitive contracts for resources, there will continue to be system dispatch, but buyers and sellers are having an impact there, too, he said.

"In the not-too-distant future, we'll see a New England that has satellite control centers around the region that will become something more like distribution system operators ... dispatching based on price, with a grid operator at the transmission level ... to make that all work at the higher voltages," Paradise said.

ISO-NE News


Rita King | © *RTO Insider*

From a utility perspective, Avangrid's vision would be to serve as the distribution system platform provider, or the smart integrator, said Rita King, senior director of smart grids innovation for Avangrid Networks.

"The smart integrator role really supports public policy and the region's targets for climate change and deployment of clean energy," King said.


David Ismay | © *RTO Insider*

David Ismay, a senior attorney with the Conservation Law Foundation, envisioned "an increasingly clean energy market" in 2030 run by Connecticut, Massachusetts and Rhode Island "with a seven-year price lock sufficient to mobilize capital for a range of zero-marginal-cost generators."


Pentti Aalto | © *RTO Insider*

Pentti Aalto of PJA Energy Systems Design asked, "Who is the customer? Is the state or the commonwealth the customer, and I'm just the bill payer? What happens if I find a cheaper way to get power and you've already contracted for me?"


CPES and NECA hosted the 2019 New England Energy Conference and Exposition in Groton, Conn., on May 14 and 15. | © *RTO Insider*

Public policy resource choices are made by elected officials, so people can vote them out of office if they disapprove, Paradise said.

Greener Cities


Alex Judd | © *RTO Insider*

Day Pitney attorney Alex Judd highlighted the increasing incidence of billion-dollar storms in the U.S. — in the Northeast in particular — and noted that the Boston Planning and Development Agency last year released the *Imagine Boston 2030* initiative focused on climate change, the first citywide plan in 50 years. (See "Climate Change is Here," *Overheard at NECA Environmental Conference 2018*.)

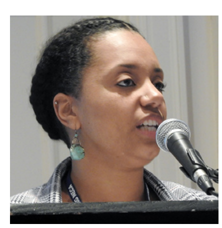

Rick Malmstrom | © *RTO Insider*

"However we get to carbon neutrality, efficiency is going to be very important, because whatever renewables you're substituting for fossil [fuels], you lower the total needed," said Rick Malmstrom, senior energy manager for the Dana-Farber Cancer Institute in Boston.

Malmstrom pointed to another influential initiative coming out of Boston: the 2013 Building Energy Reporting and Disclosure Ordinance (*BERDO*), which mandated that any building more than 50,000 square feet must report all its energy usage.

"They do have the ability to fine, but they do not want to do that," he said. "They want to help all building stock get to that kind of reduction [15% energy consumption cut over five years], so now they're exploring pathways to compliance, such as requiring energy audits be performed, etc."


Left to right: Alex Judd, Day Pitney; Rick Malmstrom, Dana-Farber; Aimee Chambers, city of Hartford; Louise Yeung, NYC Economic Development Corp; and Nithya Sowrirajan, Google. | © *RTO Insider*


Aimee Chambers | © *RTO Insider*

Aimee Chambers, director of planning for the city of Hartford, said the city represents "a great example of being able to integrate energy into its large-scale decision-making" through a zoning overhaul and related

ISO-NE News

planning processes.

"The city was most surprised to learn that people … really care about affecting the environment," she said. "We've incorporated a lot into the [building] code with relation to energy. Our code offers density bonuses if buildings use renewable energy or co-generation."

Hartford also allows building-mounted solar and wind "everywhere, and for those who produce big energy, we allow large-scale wind along our highways, and we also would welcome solar parking canopy development," Chambers said, adding that the city requires electric vehicle charging stations for lots with space for 35 cars or more.

Louise Yeung, energy portfolio manager for the New York City Economic Development Corp. (EDC), highlighted the value of leveraging a large real estate portfolio, which in her case is 62 million square feet.

Louise Yeung | *© RTO Insider*

"Part of our goal is to generate income for the city to fund other programs and functions, but we also want to make sure we are doing this with clear policy objectives in mind," Yeung said. "Sometimes those are jobs. In my portfolio's case, we are looking at emissions reductions and looking at how energy investments can support broader climate targets."

Most of the EDC's income comes from leasing, so hosting on-site renewables or generation is a way to diversify the revenue stream and realize the full potential of the assets, she said.

Nithya Sowrirajan, director of global product solutions for Google, showed how her company is using geospatial data and technology to help cities track their carbon emissions and improve their planning abilities.

Nithya Sowrirajan | *© RTO Insider*

"San Jose, Calif., was able to look at solar potential for their city as seen today in Google's *Environment Insights Explorer* and see that their roofs had [potential] capacity of 4 GW, and thus confidently set a target to be the first 1-GW solar city," Sowrirajan said. "We started with a small set of cities to pilot our platform, which of course is easier to do in our backyard in California. But as a proud New Yorker, I'm excited to be here alongside fellow panelists from New York City and Hartford to speak about smart cities and to see how we can drive partnerships farther on the East Coast." ■

Eversource Balks at ISO-NE Plan on CIP Costs

Continued from page 15

marily reflect the costs of building, operating, maintaining and ensuring the reliability of the transmission system," Eversource said.

The company said the RTO should instead consider collecting the costs under its capacity load obligation (used to recover the "missing money" not recovered by generators in the energy market) or real-time non-coincident peak load obligations (Schedule 3 reliability administration service costs). Eversource also said the RTO should create a separate billing item for CIP costs to make them transparent.

According to the New England States Committee on Electricity, transmission costs are between 11 and 18% of total electric bills for residential customers in the region. Total transmission charges have risen from about $869 million in 2008 to $2.25 billion in 2018, NESCOE says.

Asked whether ISO-NE could accommodate Eversource's proposal, Blomberg said the RTO believes its cost-allocation plan "is the most appropriate solution to ensure compensation" for the NERC compliance requirement.

"The ISO is continuing to listen and discuss this issue with stakeholders," she added.

In a *presentation* to the Transmission Committee on March 27, ISO-NE had proposed a cost-of-service reimbursement method, saying a 2017 effort to create a formula rate failed because the RTO was unable to identify a methodology to determine an IROL-critical "proxy" generator or estimate reasonable costs for compliance with the NERC standard.

ISO-NE says the lack of "clear and precise CIP requirements" in standard CIP-002-5.1a Attachment 1 may lead generators to differing interpretations on what steps they need to take. The RTO said costs disclosed by the operators of seven IROL-critical generating stations showed both one-time capital costs and recurring O&M expenses. There was no obvious correlation between costs and generator size, type or vintage, ISO-NE said.

Blomberg said a formula rate is not the same as a proxy rate approach. "Under a formula rate approach, the facility submits its specific costs for approval. A proxy rate is an estimate of the costs of a generic, but similar, facility without consideration of the actual costs. IROL-CIP facilities all have different characteristics, which make proxy rate approach extremely challenging."

ISO-NE said IROL-CIP costs should be allocated to regional network service and through or out service because accurate IROLs allow the RTO to maximize use of the transmission system.

Lowell told the committee at the March meeting that the ISO-NE would consider alternatives to the cost-of-service proposal if it had broad support within NEPOOL and had a cost estimation methodology the RTO could defend as just and reasonable.

NERC spokesman Martin Coyne declined to comment on the RTO's characterization of the CIP requirements.

"[We] can't comment on a presentation that's not ours or for security purposes discuss details on critical facilities," he said.

He added: "It is common for entities to seek information from NERC on how specific requirements in our stakeholder consensus-based standards apply to them."

Business Procedure Change Approved

In other matters, the committee approved ISO-NE's proposal to make administrative changes to Ancillary Service Schedule 2 of Section II of the Tariff and the VAR Business Procedure, along with revisions to accommodate electric storage reactive resources. The changes move requirements from the Business Procedure into the Tariff and incorporate electric storage facility language into the Schedule 2 capacity cost compensation program.

The RTO said the changes were related to FERC's Feb. 25 approval of revisions to Section II that created multiple constructs for storage devices to participate in the RTO's day-ahead and real-time energy markets (*ER19-84*). (See *FERC Accepts ISO-NE Storage Tariff Revisions*.) ■

MISO News

MISO Puts Fast-track Option on Hold

By Amanda Durish Cook

CARMEL, Ind. — MISO will pull back on a plan to create a special lane in its interconnection queue to accelerate the process for projects that demonstrate readiness for development.

The move — announced May 14 at the Interconnection Process Working Group (IPWG) — represents MISO's second about-face on the issue. After last year resisting wind developers' pleas to create, the RTO early this year said it would develop a fast-track option, with staff floating possible approaches in March. (See *MISO Details Fast-track Queue Options*.)

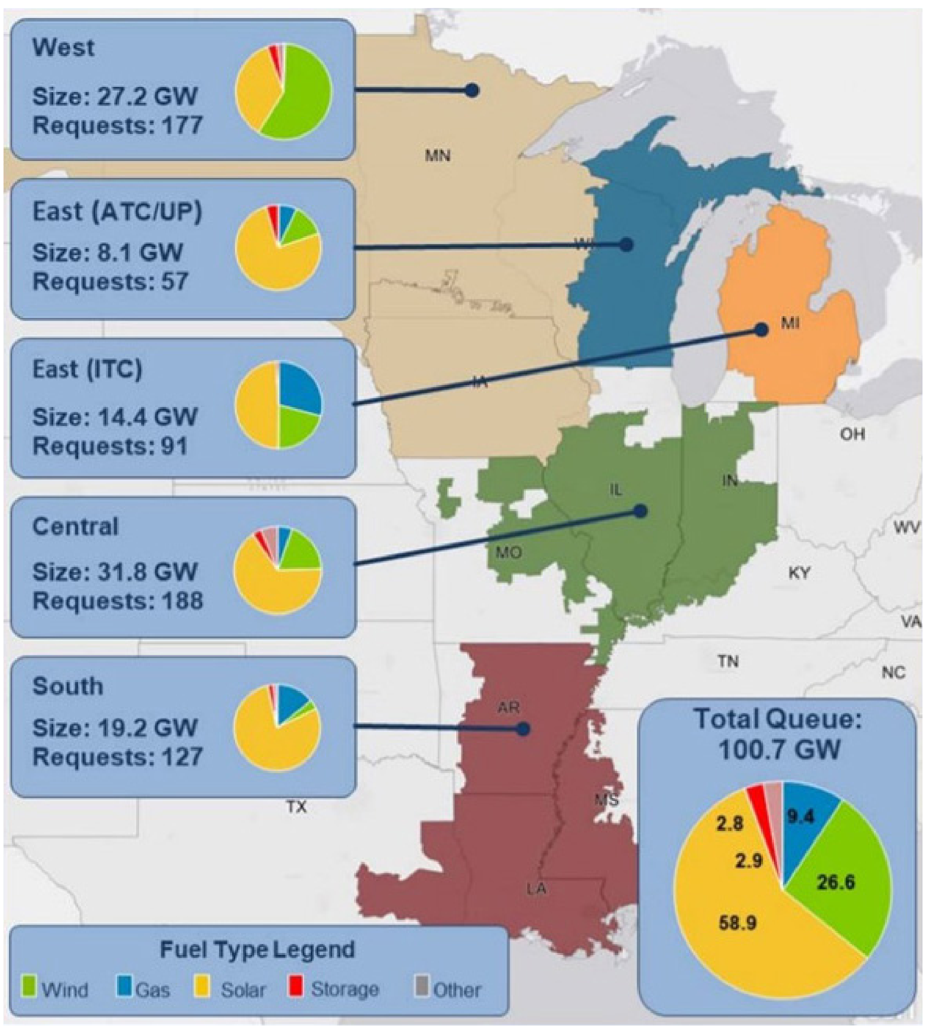
The effort would have created a separate, expedited definitive planning phase (DPP) designed to allow select projects with documented evidence they would be complete in about three to six months.

"We've decided to put this on hold until further notice," Resource Interconnection Planning Manager Neil Shah told the IPWG.

Shah said stakeholder reaction to the March presentation persuaded MISO to change course. He said a fast-track option does not have general support, with stakeholders instead urging the IPWG to improve the existing process rather than "developing a parallel path."

"Basically, stakeholders want us to improve efficiency for the existing DPP. They think it's not the right time for it."

Shah said some stakeholders pointed out that an expedited DPP "may not help projects where state regulations mandate certificates of public convenience and need," typically a two-year process.



MISO queue as of May | *MISO*

But BayWa r.e. renewable energy's Patrick Brown urged MISO to not "flush away" the proposal, but "flesh it out more."

"If you have a [power purchase agreement], you're clamoring for this," Brown said, adding that there must be multiple developers in MISO's interconnection queue that can demonstrate readiness.

MISO's queue is once again at an all-time high, now at 640 projects *totaling* 100.7 GW, with 297 projects totaling nearly 44 GW having entered the queue this year before the April 29 window close. Solar accounts for about 210 of the new projects, at nearly 30 GW.

The total queue is now about 86% wind and solar projects, with proposed solar generation (59 GW) overtaking wind (27 GW). Proposed storage projects represent about 3 GW, while natural gas projects represent more than 9 GW.

MISO's queue topped out at about 90 GW in 2018 but had fallen to about 70 GW by March because of withdrawing projects.

The RTO is only suspending the fast-track effort, not completely closing the door on the idea, Shah said, noting his staff will continue to monitor any shift in stakeholder opinions. He also pointed out there other there are "other avenues" stakeholders can pursue within the Tariff if they are simply looking to accelerate the construction of projects.

Additionally, MISO now plans to perform an intensive examination of how projects advance the queue, looking specifically at project modeling, the DPPs and agreement negotiation.

MISO Manager of Resource Interconnection Arash Ghodsian said interconnection staff will follow the April 2018 cycle of projects and collect data to examine how to reduce the length of time projects spend in the interconnection process.

"The goal is to come back in July and talk about the model development stage, talk about the process, the successes and challenges, and the opportunities for improvements," Ghodsian said.

"There are no intentions at this point to file anything," he added. He said any possible solutions will be arrived at "collaboratively" with stakeholders. ■

MISO News

MISO Promises Refile on Stricter Queue Requirements

By Amanda Durish Cook

| *MISO*

MISO plans to refile a revised version of a plan to speed up its current 500-day interconnection queue process after FERC rejected its first attempt.

The commission in March rebuffed MISO's plan to impose more stringent site control requirements and increase the milestone payments for interconnection customers, saying the RTO didn't adequately demonstrate the proposal was reasonable and not unduly discriminatory. (See ***FERC Rejects MISO Plan to Strengthen Queue Requirements***.)

However, the commission noted it could be persuaded to accept the plan if MISO could better explain its "exclusive use" site control provision, defend its proposed higher milestone fees and justify the milestone portions that would be placed at risk of forfeiture.

Neil Shah | © *RTO Insider*

MISO will address those issues according to FERC guidance and refile the proposal by July, Resource Interconnection Planning Manager Neil Shah told the Interconnection Process Working Group (IPWG) on May 14.

Shah said MISO also has the benefit of "six to eight months" of stakeholder discussion and multiple rounds of feedback on the proposal to guide adjustments.

The site control and milestone payment changes are set to take effect for projects entering the definitive planning phase (DPP) of the queue this year.

MISO will revert to its status quo process regarding the first milestone payment, which will remain $4,000/MW instead of becoming a variable cost representing 10% of the average network upgrade cost from the last three DPP cycles.

FERC had said MISO's proposal diminishes accounting certainty for interconnection customers, unfairly burdens projects in sub-regions where network upgrade costs are traditionally lower, ignores the fact that upgrade costs can vary widely across each study cycle and unfairly relies on using the costs of only preliminary network upgrades "that may not actually be built."

Shah said MISO still needs to work out how interconnection customers would demonstrate exclusive use of site control. Some stakeholders said they hope the revised proposal will reduce overlap on claimed sites for prospective projects.

FERC had said MISO's proposed language that project owners demonstrate exclusive use conflicts with a Tariff section that allows interconnection customers to submit "multiple interconnection requests for a single site" and a policy that requires customers to submit separate requests for generating units that use multiple fuel sources. The commission also said MISO's filing was "unclear" about how interconnection customers would be able to meet an exclusive-use standard.

Since then, FERC has given MISO permission to allow generating facilities using more than one fuel source — hybrid resources — to submit a single request to join the interconnection queue. (See "MISO to Process Hybrid Interconnections Under 1 Form," ***MISO Planning Week Briefs: Feb. 12-13, 2019***.) The Tariff previously prohibited customers from designating two fuel types on an interconnection request.

Shah also said MISO staff will create a "true-down" mechanism for its milestone payments, which FERC suggested in its rejection order.

"Because MISO's milestone payments have become significantly larger than the initial payment, in any future filing, MISO should consider a true-down mechanism in order to bring milestone payments back in line with the initial intent behind MISO's milestone payment structure — i.e., for those payments to provide approximately 20% of an interconnection customer's network upgrade costs. Furthermore, this type of mechanism could serve to balance MISO's proposal to make portions of the M2 and M3 milestone payments at-risk," FERC said.

The RTO also faces more work to explain its "at-risk" policy on interconnection customers' milestone fees. A percentage of milestone fees become at risk of forfeiture as customers decide to move to the next phase of the three-phase DPP. FERC said that because MISO recently removed the requirement for an affected-system analysis in the first phase of the DPP, MISO's proposal would "require interconnection customers to post at-risk milestone payments without knowledge of potential affected-system impacts that may alter their network upgrade cost estimates." FERC said the amount of risk was not properly balanced by proposed improvements to the queue process.

Finally, MISO said it will now refund milestone fees after interconnection customers make their first payment under a generator interconnection agreement. The RTO had first proposed not to refund milestone payments until a project achieves commercial operation, but FERC said the milestone refund date

Continued on page 21

MISO News

FERC Ends Examinations of TO Tax Calculations

By Amanda Durish Cook

FERC on Thursday terminated its investigations into the tax calculations included in transmission rates after several MISO transmission owners made compliance filings to remove a two-step averaging methodology that could inflate rates by underestimating tax credits.

The commission accepted compliance filings in part for MISO TOs ALLETE, Montana-Dakota Utilities, Northern Indiana Public Service Co., Otter Tail Power and Southern Indiana Gas & Electric (*EL18-138*), *as well as American Transmission Co.* (*EL18-157*) *and International Transmission Co.* (*EL18-159*). It also fully approved filings submitted by CAISO TOs GridLiance West (*EL18-158*) and Southern California Edison (*EL18-164*).

All the TOs proposed to end the use of a double averaging formula to calculate accumulated deferred income taxes (ADIT).

FERC last year ordered compliance filings and opened a Section 206 proceeding investigating TOs' use of the practice. (See *FERC Acts on Transcos' Revised Tax Calculations*.)

Some MISO TOs were using a two-step averaging methodology in their projected test year calculations of ADIT balances, but FERC said the practice makes deferred income tax credits appear lower than they should be, possibly raising rates because averaging the prorated ADIT value for the year with the beginning-of-year ADIT balance "produces a result that is disproportionately skewed towards the beginning-of-year balance." (See *FERC Broadens Challenge to TOs' Tax Calculations*.)

FERC got a bit more than it bargained for when the MISO TOs submitted compliance filings that also revised their annual ADIT true-up calculations.

The commission rejected the MISO TOs' proposed revisions to apply the IRS' proration methodology to their annual true-up calculations, saying the effort was beyond the scope of compliance.

"The filing parties' proposal to prorate certain MISO TOs' annual true-up calculations is not necessary to comply with the remedy … and is thus outside the scope of this compliance proceeding," FERC said.

It directed the TOs to make further compliance filings that include the revised ADIT calculations, this time leaving out "any other modifications or revisions."

The commission said if the TOs still want to revise their transmission formula rates to apply the proration methodology in their true-up calculations, they could make separate filings for FERC review.

METC Filing Rejected

In a proceeding separate from the other MISO TOs, Michigan Electric Transmission Co. (METC) failed to earn FERC's stamp of approval over its attempt to address the ADIT issue (*EL19-16*). In that order, the commission said that while METC's proposed removal of two-step averaging complied with FERC's directive, the company's request to include the IRS' proration methodology in its true-up calculations for all of 2019 amounted to retroactive ratemaking because the company had submitted its filing on Jan. 22.

"Although we are rejecting METC's filing, we note that it may refile its proposal to apply the IRS' proration methodology to its true-up calculations, provided that its proposed revisions apply prospectively, in a separate [Federal Power Act Section] 205 filing. The commission will evaluate the proposal at that time," FERC said. ■

Robert Mullin contributed to this article.

MISO Promises Refile on Stricter Queue Requirements

Continued from page 20

should both prevent queue gaming and not tie up an interconnection customer's capital for too long.

MISO currently issues milestone refunds 45 days after a GIA becomes effective, but it contends that deadline opens up the process to gaming because an interconnection customer could withdraw its project immediately after executing a GIA, "when its milestone payments have been transferred to the transmission owner but before the transmission owner has spent anything on construction costs, which would give the interconnection customer essentially a full refund of its milestone payments."

Shah said RTO staff sought to arrive at a refund date that wasn't too burdensome for interconnection customers while discouraging gaming and mitigating the impact of withdrawing projects on other projects.

Shah said he would return to the IPWG in July for stakeholder review of the modified proposal with a goal to refile within the same month.

Other Interconnection Filings

While FERC rejected the site control and milestone changes, on Wednesday it accepted a different MISO queue proposal to allow the transfer of interconnection rights for existing generators that have been retired, demolished or replaced with new generation (*ER19-1065*).

U.S. Rep. *Kelly Armstrong* (R-N.D.) and Sen. Tina Smith (D-Minn.) each wrote in support of the proposal, saying it would allow owners of aging generation to make cleaner upgrades without risking their interconnection rights. (See *Senator Backs MISO Generator Replacement Proposal*.)

MISO also filed a partial compliance with FERC Order 845 on May 10 to address a directive that RTOs establish an expedited queue process allowing interconnection customers to use or transfer surplus interconnection service at existing facilities (*ER19-1823*). MISO's filing proposes to rename its existing net zero interconnection option to "surplus interconnection service" and include interconnection and steady state analyses, while removing an existing competitive solicitation process for surplus interconnection service and clarifying that the original interconnection customer or affiliates have priority rights to any surplus service. (See *Little Work Needed to Comply with Order 845, MISO Says*.) MISO said it will make another compliance filing for the remainder of Order 845 *directives* by Wednesday.

On a related note, MISO also *plans* to make a FERC filing in either June or July to create a shared-use agreement for projects sharing a single interconnection facility. MISO is requiring that any consent agreement include project configurations, facilities ownership terms and an explicit division of rights and responsibilities, including operation, maintenance and repairs. ■

MISO News

Countering Stakeholders, MISO Rebuffs Non-TO SATA Idea

By Amanda Durish Cook

MISO last week shut down the prospect of allowing non-transmission owners to operate storage-as-transmission assets (SATA) in the RTO's initial ruleset for the resources, just as a new poll revealed that most stakeholders want to devote more time to weighing the possibility.

Planning Advisory Committee sectors last month voted via email in favor of further discussion on a DTE Energy proposal that MISO's first SATA rules include a path for non-TOs — as well as TOs — to own and operate SATA. (See *MISO PAC Contemplates SATA Shakeup* and *MISO Floats Draft Storage-as-Tx Rules*.)

The motion passed with 5.5 votes in support, 2.5 votes in opposition and two abstentions from MISO's Coordination Member and State Regulatory Authorities sectors. Opposition votes came from the Transmission Owner and Eligible End-User Customers sectors, with the transmission developer sector splitting its vote. MISO's 10 sectors can divide their single vote to reflect differing opinions within a sector. Results were revealed during a special May 15 conference call of the PAC.

MISO determined earlier this year that only registered TOs would be eligible to own SATA in order to avoid introducing complexities around cost recovery, particularly related to how non-TOs would be compensated for providing transmission services.

DTE has said non-TO SATA should be permitted to bypass the interconnection queue and connect to MISO's transmission system through newly conceived storage interconnection agreements. Absent that provision, DTE has said MISO's SATA ruleset would create preferential treatment for TOs and create barriers to entry for storage.

Still, MISO is staying the course that SATA should only be developed by existing or eligible new TOs, with staff explaining that non-TO-owned SATA is simply too complicated to introduce.

Jeff Webb | © *RTO Insider*

"While we appreciate the idea and the effort that DTE and other stakeholders have put into this … we simply don't accept this proposal," MISO Director of Planning Jeff Webb said.

Webb said MISO's upcoming filing will detail the discussion the PAC has held on the possibility of non-TO SATA. However, he said the RTO has a "fundamental disagreement" that an asset used exclusively to address a transmission issue and is connected to the transmission system can simultaneously be a non-transmission asset.

"We think FERC's been pretty clear that storage should exist within current generation, transmission and distribution [classifications]," Webb said.

"Obviously there will be some sectors that are disappointed in this result, especially with the PAC vote," DTE's Nick Griffin said.

MISO still maintains that non-TO-owned storage can already enter the transmission planning process under the non-transmission alternatives (NTAs) *provision* (*BPM 020*), which allows generation and demand-side resources to serve as alternatives to transmission proposals and be studied under the annual Transmission Expansion Plan (MTEP). However, NTAs must either scale the interconnection queue or connect via the distribution system. Under the proposed SATA rules, a transmission system connection without a queue requirement would be reserved only for TOs that operate SATA.

Stakeholders criticized the NTA provision as being seldom used. Griffin said it is essentially "there for show, but not for use."

Webb agreed that the NTA process could use modeling improvements.

Invenergy also repeated criticisms that MISO's first SATA rules are too narrow, are discriminatory and were crafted in a "deficient stakeholder process."

But MISO said it created rules "appropriate in addressing storage as transmission."

"We do not agree that treatment of storage as a transmission asset is discriminatory, nor that the nearly yearlong stakeholder process has been deficient," the RTO said.

MISO Manager of Expansion Planning Lynn Hecker said staff are still working through how to estimate the useful life, degradation and lifetime cost of ever-evolving storage technologies to be able to evaluate them against traditional wires in the MTEP.

The RTO plans to make its first SATA filing with FERC in late June. Webb said he would return to the June PAC meeting with a final proposal. ■

MISO News

Refund Hearing Ordered in MISO-PJM Pseudo-tie Complaint

By Amanda Durish Cook

Refunds appear imminent in a three-year dispute over MISO and PJM's past practice of double-charging pseudo-tied generation for congestion fees after FERC last week ordered settlement proceedings to determine how much the RTOs must remit to address the redundant costs incurred from 2016 onward (*EL16-108*).

The issue stretches back three years to when Tilton Energy lodged a complaint against the RTOs for assessing overlapping congestion charges on pseudo-tied resources. American Municipal Power, Northern Illinois Municipal Power Agency, Dynegy and Illinois Power Marketing soon filed similar complaints. FERC consolidated the proceedings.

The RTOs introduced a temporary rebate program in 2017, then began including pseudo-ties in the day-ahead scheduling process in 2018 to end redundant congestion costs. (See *MISO, PJM Pursue Pseudo-Tie Double-Charge Relief*.) In March, MISO got FERC approval for a second piece of the solution, where participants with pseudo-tied resources can use the day-ahead market to hedge against real-time congestion.

In its order, FERC noted that it has already accepted two filings apiece from MISO and PJM to address overlapping charges and has since discovered that those proposals have eliminated the congestion overlap. But those corrections come too late for the transmission customers already assessed those charges, FERC said.

"We find that the potential for overlapping or duplicative charges for congestion existed prior to the effective dates of the revisions," the commission said.

As such, FERC established settlement procedures to determine the appropriate refunds owed to owners of pseudo-tied generation. The commission said if the involved parties don't settle, a settlement judge will decide the case by May 18, 2020. FERC set a refund effective date of Aug. 25, 2016.

FERC: MISO Congestion and Admin Charges Appropriate

However, the refunds will not include the costs of MISO's non-duplicative congestion and administrative charges that Tilton also challenged.

| © RTO Insider

Tilton claimed MISO violated its Tariff by erroneously using financial schedules to assess charges on pseudo-tied generation, arguing the schedules are meant to represent contracts between two market participants and that MISO is not a counterparty to the pseudo-tie transactions.

The company said MISO circumvented a Tariff provision and implemented Business Practices Manual language when it used its financial schedules to record transmission transactions for pseudo-tied generation "despite the nonexistence of a bilateral transaction that is a prerequisite for the use of a financial schedule."

Tilton also argued that MISO's assessment of real-time congestion costs against generation pseudo-tied from MISO to PJM is improper because the charges cannot be hedged and are "inconsistent with market fundamentals." The company asked FERC to put a stop to MISO's assessment of congestion and administrative charges.

In response, MISO argued that Tilton failed to show the RTO was acting counter to its Tariff and said the complaint should be thrown out. MISO also said Tilton failed to initiate dispute resolution procedures prior to filing the complaint, a break with commission precedent.

"Although Tilton has purchased long-term firm transmission service from MISO to PJM, paying for transmission service does not exempt Tilton from paying for congestion and losses," the RTO explained.

The commission sided with MISO, ruling that Tilton must pay to use the MISO system.

"We conclude that MISO's assessment of congestion costs and administrative charges on Tilton does not violate the MISO Tariff. Specifically … we find that the MISO Tariff authorizes MISO to assess congestion costs and administrative charges on pseudo-tie transactions. We also find that it was not a violation of the MISO Tariff for MISO to use financial schedules as a vehicle for imposing congestion and administration charges on Tilton," FERC said.

The commission pointed out Tilton is a MISO transmission customer taking transmission service "to facilitate its pseudo-tie transactions" and is thus required to pay applicable charges.

Pseudo-tie transactions that use the MISO system nevertheless contribute to the RTO's real-time congestion, FERC added. ■

NYISO News

NYPSC Modifies Standby Rate Design for DERs

By Michael Kuser

The New York Public Service Commission on Thursday continued to tweak compensation and billing for distributed energy resources, adjusting the structure of existing standby and buyback service rates and extending standby rate exemptions for two years (Case *15-E-0751*).

The PSC held its regular monthly session in Albany on May 16.

The PSC's *order* modifies rates "to more accurately reflect costs and benefits and to ensure that those rates are available to all interested ratepayers."

Ted Kelly

"Standby service rates generally apply to customers who have on-site generation that serves much of their load but still depend on the utility to provide partial or backup service," said Ted Kelly, assistant counsel for the Department of Public Service. The buyback rates determine the price customers receive for selling excess energy back into the grid.

"With interval metering becoming much more widely available due to the rollout of advanced metering infrastructure (AMI) throughout New York state, mass market standby service rates no longer need to be limited to flat fees and volumetric energy usage," the PSC said. "Rather, rates for mass-market standby service can be measured and billed on the basis of demand in the same manner as the standby service rates applicable to larger customers."

The order requires that all customers be eligible to opt into a demand-based rate option, irrespective of whether they have on-site DERs. It also requires greater granularity by using off-peak, on-peak and super-peak charge components, and allows the load of multiple customers in multiple buildings to be offset by a common generator.

"This is obviously a complex topic," PSC Chair John Rhodes said. "Though a complicated subject, this is a very practical approach going forward."

John Rhodes

Commissioner Gregg Sayre said he was "comfortable establishing a rate design that more closely tracks the cost of service."

Gregg Sayre

"Standby rates have been controversial and hotly debated," said Commissioner Diane Burman, who concurred in the approval.

Diane Burman

"I do think we were overly ambitious in 2015 in thinking that it could happen overnight and that the signal was we were ready to go."

The order also modifies the design and administration of buyback service tariffs to eliminate or reduce barriers to deployment of DERs, and clarifies the application of grid access demand charges for energy storage systems.

The commission also voted unanimously to continue existing statewide exemptions from standby rates, and to extend the in-service date deadline for eligible DERs until May 31, 2021 (Case *19-E-0079*).

These exemptions apply to certain DERs with a capacity of 1 MW or less, including fuel cells, wind, solar thermal, solar photovoltaic, biomass, tidal, geothermal, methane waste-powered resources, and efficient combined heat and power projects, the order said.

New York utilities must implement the rule changes effective July 1.

Grid Prepared for Summer

DPS staff presented the commission a *report* on summer electricity preparedness that forecasts a 1 to 3% decline in energy prices compared with last summer, depending on load zone and weather conditions.

"This is very comforting for New Yorkers," Rhodes said.

The state bases its energy price forecasts on futures trading at the New York Mercantile Exchange, and the commission said that financial hedging by utilities will also reduce any price increases this summer.

Warren Myers

"The big driving factor of course is ICAP [installed capacity], which tends to be fairly stably high in the summer downstate and, year after year, quite low upstate," said Warren Myers, DPS director of market and regulatory economics. "And with respect to delivery charges, those, by their design through rate cases, are very stable."

New York has sufficient generating capacity resources to supply expected customer demands and all of the state's electric utilities are prepared to serve those expected customer demands, the report said. Peak load this summer is forecast to be 32,382 MW, down slightly from last year. ■

NYISO News

NYISO Business Issues Committee Briefs

Collateral Change for Foreign Market Participants

NYISO's Business Issues Committee last week approved a proposed Tariff revision that redefines acceptable collateral for foreign market participants, largely to head off cumbersome bankruptcy proceedings in foreign jurisdictions.

Sheri Prevratil, the ISO's manager of corporate credit, presented *analysis* on the proposal to allow only entities formed or incorporated in the U.S. or Canada to post cash collateral.

The changes modify section 26.6.1 of the Services Tariff and affect only four market participants, she said.

NYISO currently allows market participants to post either unsecured or secured credit, with participants not meeting unsecured credit standards required to provide secured credit.

The ISO is seeking the change to avoid the potential costs required to secure and use collateral in the case of a foreign bankruptcy. Given the potential number of jurisdictions at issue worldwide, it is not feasible for the ISO to evaluate laws in all jurisdictions to ensure its interest in cash collateral would be adequately protected, Prevratil said.

State of the Market: Peak Load Up 7%

Rising natural gas costs and increased load levels were the two key factors that drove up NYISO electricity prices by 23 to 36% in 2018, Pallas LeeVanSchaick of the Market Monitoring Unit told the BIC while presenting a *summary* of the *2018 State of the Market Report*.

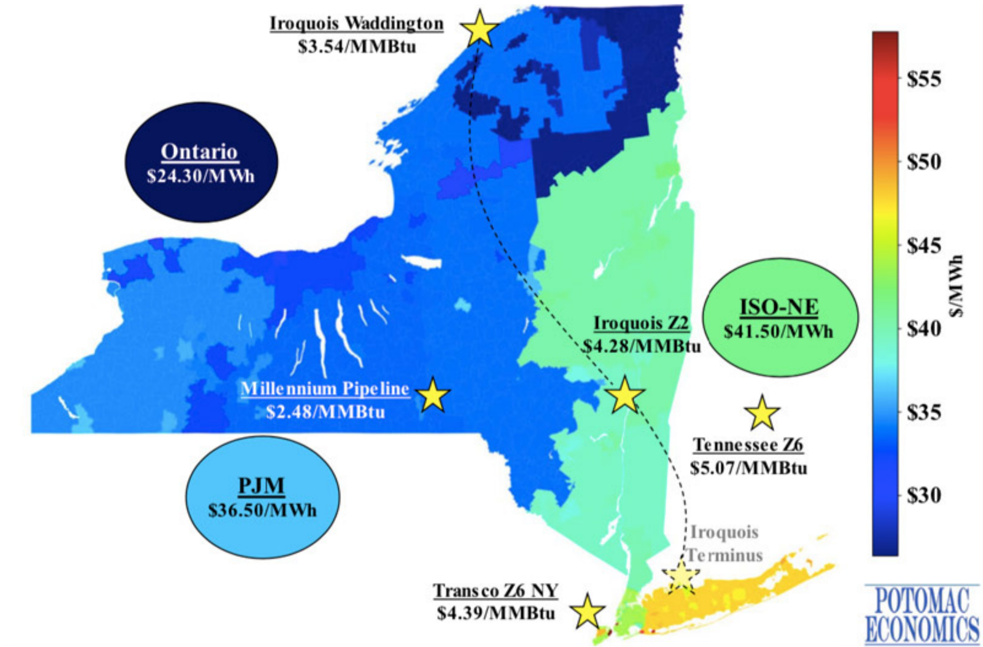
The report showed peak load up 7% last year — "quite a large increase," LeeVanSchaick said.

Average gas prices rose 21 to 47% across the state, with much of the increase caused by a cold spell in early January, while gas price spreads between western and eastern New York fell, leading to less west-to-east transmission congestion, LeeVanSchaick said.

The state's electricity consumption rose from low levels seen in 2017, with average load up 3% and higher congestion occurring within New York City and Long Island.

"These factors also increased day-ahead congestion revenues, which we saw go up by 21% to just over $500 million in 2018," LeeVanSchaick said.

He said the current capacity market produces prices for only the four modeled capacity regions and may produce incentives for excessive investment in some export-constrained areas and insufficient price signals for investment in import-constrained load pockets or in areas that improve reliability elsewhere, such as Long Island.



Declining gas price spreads helped to reduce NYISO's west-to-east transmission congestion in 2018, the Monitor found. | *Potomac Economics*

The four-zone model may not allow prices to change efficiently as units retire and enter, or transmission is built, and incentive issues become more acute with anticipated policy-induced retirements and new resource additions, as well as resource retention necessary to support local reliability in NYC load pockets, he said.

Based on those considerations, the Monitor recommends implementing a more granular locational capacity pricing mechanism, LeeVanSchaick said.

Included among the multiple policies aimed at removing capacity sources are the Indian Point nuclear plant retirement, coal plant retirements and the state's Department of Environmental Conservation proposal to curb emissions from peaker plants. (See *NY DEC Kicks off Peaker Emissions Limits Hearings*.)

LeeVanSchaick said retirement of inflexible generation is needed to make room for state-sponsored resources and flexible resources that help integrate them, and that requires efficient market incentives.

"Even if those [public policy] resources are not justified based on economics and competitive entry, there is still an opportunity to get an exemption through a Part A test ... which in New York City essentially allows for 6% excess capacity," LeeVanSchaick said. The Monitor's Part A test is intended to exempt from mitigation any resource deemed to be economic compared with a NYISO forecast, allowing that resource to bid into the capacity market on the same basis as other resources.

Updates to Economic Planning Process Manual

The BIC approved limited updates to the Economic Planning Process Manual, the first since February 2016, modifying the description of historic congestion data reporting.

Timothy Duffy, the ISO's manager of economic planning, delivered a *summary* of the changes, providing a brief overview of the separate generation deactivation process outlined in the overview section of the Comprehensive System Planning Process.

The changes correct NYISO web links and make ministerial revisions for user readability, standardization of tariff references, inappropriate capitalizations and use of Tariff-defined terms, Duffy said.

NYISO News

NYISO-PJM JOA Revisions

The BIC approved *revisions* to NYISO and PJM's Joint Operating Agreement, which the Management Committee will consider on May 20 and, if approved, will go to the Board of Directors in June, ahead of a joint FERC filing.

Total redispatch settlement last year was "very small," said Cameron McPherson, NYISO operations analysis and services analyst.

NYISO and PJM last September filed with FERC a joint request for waiver of the JOA to permit them to add the East Towanda-Hillside tie line as a market-to-market flowgate. (See "NYISO, PJM Revising JOA for Tie Line Issues," *NYISO Business Issues Committee Briefs: March 13, 2019*.)

Robert Pike, NYISO director for market design and product management, presented the monthly Broader Regional Markets *report* and highlighted the ongoing work to revise the JOA to address coordination on flowgates similar to the East Towanda-Hillside Tie Line.

Pike also highlighted continued stakeholder discussions regarding deliverability requirements for external capacity suppliers, including new rules such as those approved at the April BIC. (See "New External SRE Penalty," *NYISO Business Issues Committee Briefs: April 17, 2019*.)

The requirements relate to New York capacity market eligibility, and the objective of the effort is to better understand any obstacles preventing external resources from delivering capacity-backed energy to the New York Control Area border.

Under the new proposal, any external resource that fails to meet the criteria will be subject to the penalty, which is equal to 1.5 times the applicable spot price multiplied by the number of megawatts of shortfall and the percentage of the supplemental resource evaluation call hours to which a supplier fails to respond.

In a separate matter, the ISO is reviving its Metering Working Group, with meetings starting in July on technical issues around metering infrastructure for distributed energy resources and storage.

LBMPs Drop 25% in April

NYISO locational-based marginal prices averaged $28.01/MWh in April, down about 25% from March and the same month a year ago, Pike said in delivering the monthly operations *report*. Year-to-date monthly energy prices averaged $40.12/MWh, a 27% decrease from a year ago.

Day-ahead and real-time load-weighted LBMPs came in lower compared to March. Average daily sendout was 371 GWh/day in April, lower than 411 GWh/day in March and 390 GWh/day in the same month a year ago.

Transco Z6 hub natural gas prices averaged $2.37/MMBtu for the month, down 24% from March and 15.1% from a year ago.

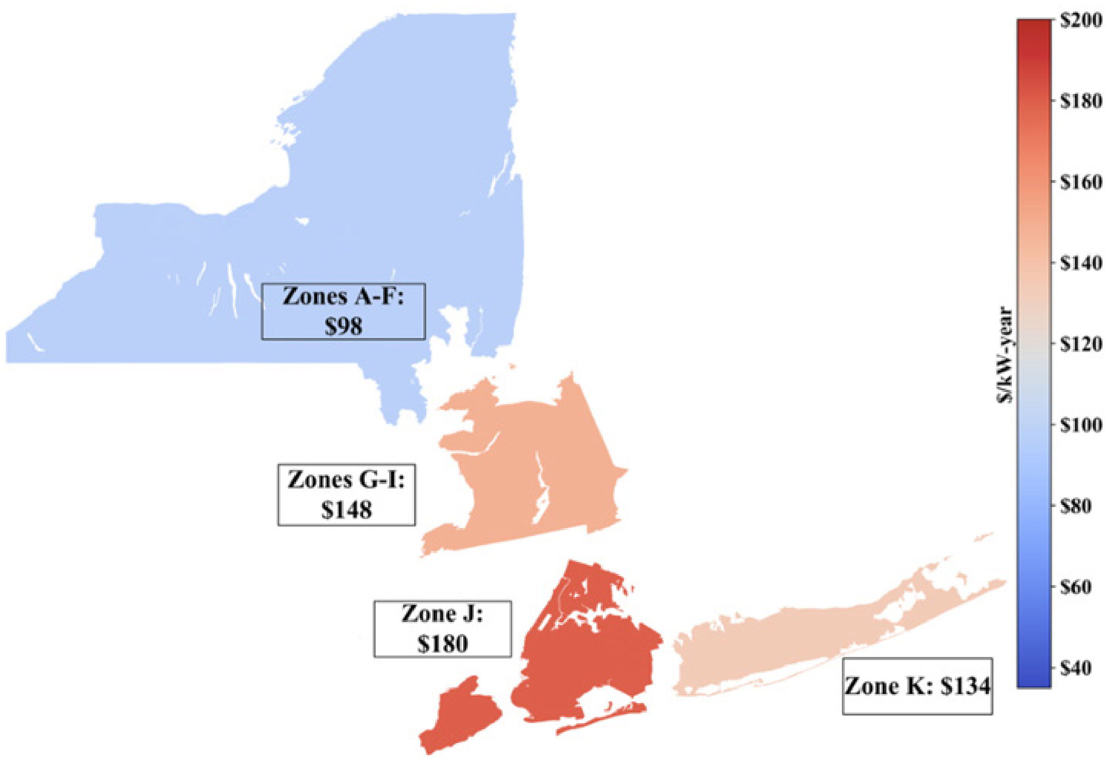
Distillate prices were down 1.5% year over year and up slightly from the previous month, with Jet Kerosene Gulf Coast averaging $14.63/MMBtu, compared to $14.18/MMBtu in March, while Ultra-low Sulfur No. 2 Diesel NY Harbor rose to $14.72/MMBtu from $14.18/MMBtu in March.

April uplift increased to -15 cents/MWh from -33 cents/MWh in March, while total uplift costs, excluding the ISO's cost of operations, came in higher than those of the previous month.

The ISO's 20-cent/MWh local reliability share in April was down from 31 cents the previous month, while the statewide share climbed to -35 cents/MWh from -64 cents in March.

The Thunderstorm Alert cost was 1 cent/MWh, unchanged from March. ■

— Michael Kuser



The Monitor contends that NYISO's four-zone capacity market may not be granular enough to send appropriate price signals to constrained regions that need new resources. | *Potomac Economics*

NYISO News

LS Power Gets Incentive for NY Public Policy Project

FERC on Thursday granted LS Power Grid New York's (LSPG-NY) request for an abandoned plant incentive for a transmission project approved by NYISO (*EL19-30*).

LSPG-NY (formerly known as North American Transmission) had partnered with the New York Power Authority to jointly propose two 345-kV transmission projects to address capacity shortfalls at the Central East (Segment A) electrical interface and Upstate New York/Southeast New York (Segment B) interface.

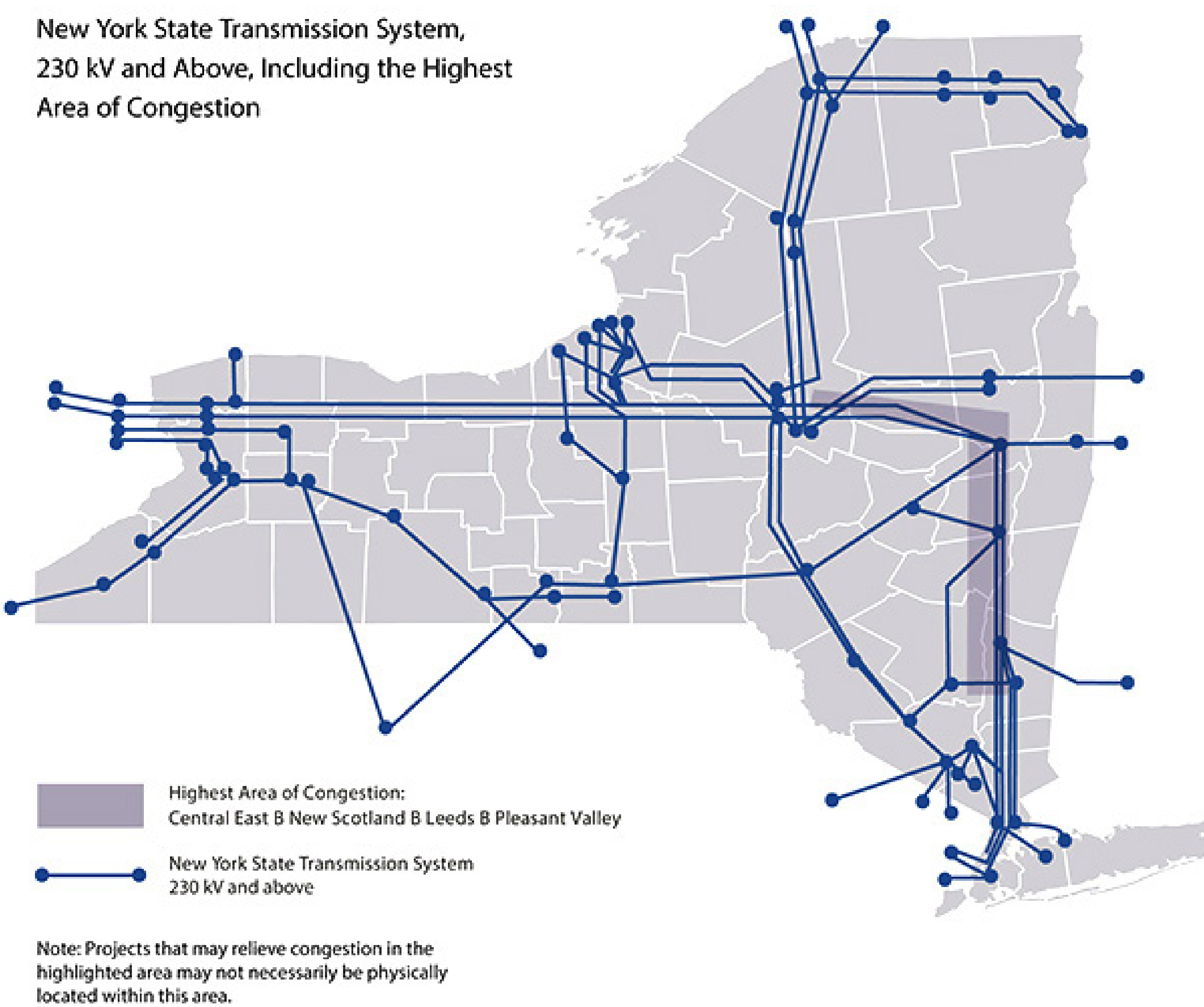
NYISO's Management Committee had backed both projects — part of the broader AC Public Policy Transmission Project — but the ISO's Board of Directors in April selected only one of them, awarding Segment B to a competing proposal by National Grid and New York Transco. (See *NYISO Board Selects 2 AC Public Policy Tx Projects*.)

"In particular, we find that LSPG-NY's Segment A project is entitled to the rebuttable presumption that it meets [Federal Power Act] Section 219's requirement that the project will ensure reliability and/or reduce congestion because it has been approved through a relevant regional transmission planning process," the commission said.

LSPG-NY said in its petition that NYISO estimated that Segment A will cost $750 million (in 2018 dollars, including 30% contingency).

The commission rejected LSPG-NY's request for the incentive for its Segment B project, as NYISO did not select it. The company filed its request in January. ■

— Michael Kuser



| LSPG-NY

PJM Revisits Gas Pipeline Contingency Plan

By Christen Smith

PJM's Market Implementation Committee meeting on May 15 | © *RTO Insider*

VALLEY FORGE, Pa. — PJM asked for stakeholder feedback last week about how to reshape its gas pipeline contingency plan, three months after FERC turned it down for lacking specificity and clarity.

Thomas DeVita | © *RTO Insider*

"We talked with FERC staff to get a read on what they want to see in a new proposal," Thomas DeVita, PJM senior counsel, told the Market Implementation Committee on Wednesday. "We got an insight to their thinking. … The key point is the commission wants to see a meeting of the minds between generators and pipelines."

On Feb. 19, FERC rejected the stakeholder-approved mechanism that would have implemented a process for market sellers seeking cost recovery for certain gas contingencies associated with the RTO's instruction to temporarily switch to an alternative fuel or alternative fuel source because of pipeline breaks or the loss of compressor stations (*ER19-664*). The proposal included nine cost categories of switching costs, including park-and-loan service charges and overrun charges.

The commission said PJM's definition of penalty was "unreasonably narrow and unsupported" because pipeline tariffs delineate between penalties and fuel-switching costs in different ways, meaning what appears to be an appropriate cost for one pipeline could be considered a penalty for another. FERC also faulted PJM for not including events that might trigger fuel-switching directives in its Tariff and for lacking procedures for dealing with such contingencies through the Capacity Performance market design. (See ***FERC Rejects PJM's Gas Contingency Pipeline Proposal***.)

DeVita said commission staff discouraged PJM from submitting an itemized list of switching costs, as it did in the first filing, and instead focus on procedures surrounding "explicit authorization" to switch between pipelines and any new limitations on the amount of gas burned after the switch occurs. Rich Brown, manager of PJM's system operator training, said FERC's focus on authorization and fuel burned reflects the commission's insistence on ensuring reliability is maintained during any switch.

David "Scarp" Scarpignato of Calpine said that approach would not protect his company's interests.

"I'm not comfortable that we just leave it open and send it to FERC with no guidance on what's a coverable cost and what's not," he said. "Just getting over the hurdle of notice is not enough to give us confidence that our costs will be recovered."

In a January filing with FERC, Duke Energy and East Kentucky Power Cooperative said they generally supported the idea of compensating generators for switching fuels, but they worried that PJM's enumerated categories didn't capture all the possible costs. Without an exhaustive list, they said, generators lacked financial incentive to make the switch or the ability to recoup expenses after-the-fact.

Marji Philips, Direct Energy's director of RTO and federal services, told the MIC that if generators know PJM will order the switch — instead of generators making the call themselves — the cost of fuel switching is transferred to customers instead. The filing isn't clear as to whether generators who can't perform will incur CP penalties, either, she said.

"This is so fundamentally flawed," Philips said. "It is not pipelines that do the switching. It's whoever owns the capacity on the pipeline. We need to rethink this and reframe how we think about this."

The Independent Market Monitor and the PJM Industrial Customer Coalition further alleged that the RTO's gas-electric coordination remains an information-sharing process, therefore PJM can't give operational instructions to pipelines. Moving customers with firm contracts off some pipelines — while others with lower levels of service remain unaffected — may discourage the former group of market sellers from taking proper steps to obtain reliable back-up fuel sources, they said.

The D.C. Office of the People's Counsel crafted the Operating Agreement and Tariff changes detailed in the rejected filing after earning a majority of stakeholder support at the December meeting of the Markets and Reliability Committee.

The supermajority vote was a victory for load interests who opposed a Calpine-authored plan endorsed at the MIC in November. That proposal would have developed a formula for cost recovery to be filed with FERC that did not include pipeline penalties.

Although ongoing services generally include cost recovery formulas, DeVita said FERC may interpret the "rare" event of generators seeking fuel-switching reimbursement as incomparable.

"We are very concerned about cost to load," said Adrien Ford of Old Dominion Electric Cooperative. "We are also very concerned about generators mitigating their own risk. We are in no man's land now." ■

PJM News

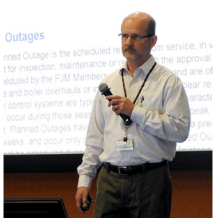
PJM Operating Committee Briefs

Generation Outage Revisions Delayed

VALLEY FORGE, Pa. — PJM staff agreed last week to delay approval of revisions to generation outage procedures after stakeholders raised concerns over potential market consequences.

Bob O'Connell | © *RTO Insider*

Bob O'Connell, director of regulatory affairs and compliance for Panda Power Funds, pressed the Operating Committee on May 14 to defer a vote on changes to Manual 10, saying the proposed language would encourage resource owners to distort prices in their favor.



Vince Stefanowicz | © *RTO Insider*

Vince Stefanowicz, PJM senior lead engineer, said the manual specifies that generators must submit outage requests corresponding to the time frame that they will be unavailable because of a transmission facility outage — and, under the proposed language, in the event of a PJM-identified stability limitation.

O'Connell said PJM's decision to remove supply from the market to address stability constraints will result in some units committing at price-based offers, rather than cost. Under PJM's rules, only the affected generator would know of the constraint, O'Connell said, therefore gaining a competitive advantage over other units and possibly incorporating greater mark-ups into their offers.

As a solution, O'Connell suggested PJM implement a closed-loop interface around the affected resource that restricts the output to below the stated stability limit — and it must be used in each of the markets. He also encouraged the RTO to publicize stability limits on OASIS prior to contacting the affected generator.

"I think Bob has raised a legitimate issue," said Mike Bryson, PJM's vice president of operations. "But we have an interim issue that this practice will be enforced until we come up with a solution. I don't know how to resolve that outside a clarification in the manual."

The committee agreed to delay the revisions — and remove stability-related changes from Manual 3 revisions that were approved earlier in the meeting — until the issue is resolved.

O'Connell said he will present a problem statement and issue charge at the June meeting of the Market Implementation Committee detailing his proposed solution.

BTM Solar Penetration Mimicking CAISO Duck Curve

Increasing penetration of behind-the-meter solar generation creates a dramatic load shape in certain PJM zones during spring and fall months, mimicking CAISO's infamous "duck curve," staff *said*.

Joseph Mulhern | © *RTO Insider*

Joseph Mulhern, PJM senior engineer, told the OC that significant growth in both grid-connected and BTM solar units over the last decade have caused load forecasting challenges, particularly during shoulder seasons when reduced electricity demand results in overgeneration.

"Since the duck curve became a popular concept ... do we see anything reminiscent of this?" Mulhern said. "If you look in the right places at the right times, we do."

CAISO first introduced the idea of the duck curve in 2013 to illustrate how rapidly expanding solar generation was impacting the system. Solar energy often peaks midday when electricity usage, particularly in the spring, may be lower than usual. The resulting curve resembles a duck — hence the name — which has become common nomenclature when describing the challenges of harnessing the full potential of solar generation. (See *Report: Calif. 'Duck Curve' Growing Faster than Expected*.)

Mulhern presented sample load shapes from 24-hour periods in March — the peak season for the duck curve in PJM —and said traditional forecasting methods failed to capture all of the 3,304 MW of BTM solar currently online. The RTO can't access unit-specific data for BTM generation like it can for the more than 1,500 MW of grid-connected solar panels, so staff has implemented a "reconstituted load" calculation to fill in the gaps.

The reconstituted load "retrains" the existing model by adding historic measured load and estimated BTM generation together. Staff then subtract forecasted BTM generation to get a more accurate picture of how solar impacts load shape — but it's not exact.

"All of this is evidence that our load forecasting process needs to have some changes made beyond our traditional approach," Mulhern said.

Staff will continue educating the OC about existing BTM business rules over the course of several months before suggesting manual revisions to better account for the grid's diversifying resource mix.

Quad Cities RAS Unnecessary

Exelon said recent analysis from PJM and Commonwealth Edison determined a remedial action scheme (RAS) in the Quad Cities region of Illinois and Iowa is no longer necessary to meet planning criteria.

The Quad Cities RAS prevents instability for a three-phase fault during line outages and thermal overloads during multiple line outages. Exelon said incremental grid reinforcements reduced the need for the scheme. The company will disable the RAS by the end of year with complete removal in 2020.

Manuals Endorsed

The committee unanimously endorsed the following manual changes:

- Manual 1: Periodic cover-to-cover *review* to update terminology and guidelines for control center and data exchange requirements.
- Manual 3: Biannual *review* to update transmission operating procedures, excluding references to stability.
- Manuals 11 and 13: *Clarifies* the impact of operationalizing gas contingencies on reserve requirements and reserve market eligibility.
- Manual 13: Periodic cover-to-cover *review* and changes to align with new Markets Gateway functionality for resource-limitation reporting to be implemented July 1.
- Manual 36: Annual update *requirement*.

Stakeholders also approved an annual review of the OC's *charter*. ■

— Christen Smith

PJM News

PJM PC/TEAC Briefs

Benefit-cost Analysis Assigned to Task Force

VALLEY FORGE, Pa. — PJM's existing Market Efficiency Process Enhancement Task Force will tackle concerns raised by the Independent Market Monitor over its benefit-cost analyses for transmission projects.

PJM Director of Infrastructure Planning Sue Glatz told the Planning Committee on Thursday that staff agreed the issues raised in the Monitor's problem statement last month would be best addressed in the task force's third phase. (See "Revisit Benefit-cost Analysis, Monitor Says," *PJM PC/TEAC Briefs: April 11, 2019*.) Glatz stood in for PC Chairman Ken Seiler.

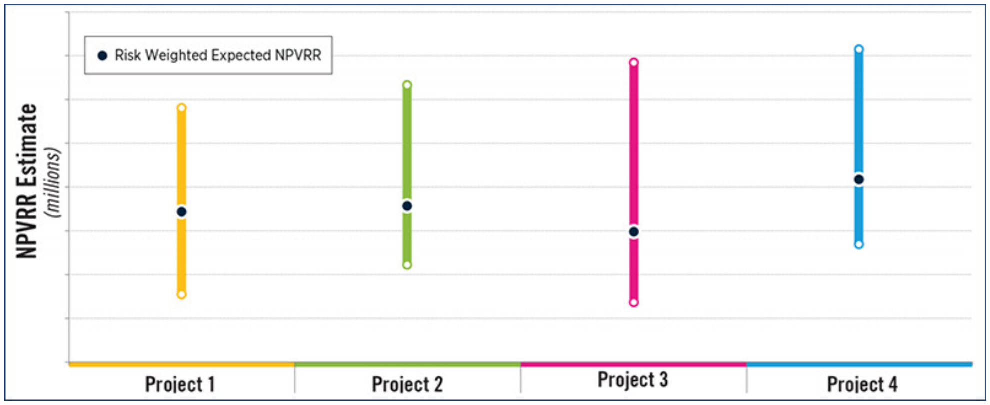
The Monitor said last month that PJM's current benefits calculation ignores increased congestion in all zones resulting from a transmission project. Specifically, the benefit-cost analysis does not account for the fact that transmission project costs are not subject to cost caps and may exceed estimated costs by a wide margin. When actual costs exceed estimated costs, the benefit-cost analysis is effectively meaningless, and low estimated costs may result in inappropriately favoring transmission projects over market generation projects or the option of no project at all, the Monitor said.

Generation Interconnection Requests Update

PJM proposed *revisions* to its generation interconnection requests process, as detailed in Manual 14G.

Lisa Krizenoskas, PJM senior engineer, said the first proposed change expands rules for demand response found in section 1.7. Staff propose directing on-site generators used to reduce load that participate as DR to Manuals 11 and 18 for further guidelines, while requiring the portion of any such generator that injects power past the point of interconnection to follow the existing interconnection process outlined in Manual 14G.

PJM also proposes a site control term of three years — two years for projects of 20 MW or less — commencing on the first day of the new services queue in which the customer submits its request. Extensions must be exercised by the developer at the time site control evidence is given to PJM.



Side-by-side comparison of estimated project costs. The bars represent the possible spectrum of cost for each project, with the bottom of the bar representing the project sponsor's cost estimate and the top point indicating an independent consultant's estimates. | *PJM*

New Fee Structure for Cost Containment Needed

PJM said its reconfigured cost-containment process will charge developers a lot more money, even for projects valued at less than $20 million.

Mark Sims, PJM's manager of infrastructure coordination, said the old tiered approach, approved in 2014, doesn't account for the increased cost of the new comparison framework that involves independent consultant review and legal and financial analyses.

"A lot of work is going to be done in parallel, which is going to increase costs," Sims said. "A lot of projects up to $100 million will need extensive analysis. That's just the bottom line. We aren't sure the existing fee structure is going to work."

Currently, PJM charges nothing for cost-containment review of projects $20 million or less. Projects up to $100 million cost $5,000 to review and larger projects incur a $30,000 fee.

Sims said the expense of paying independent consultants for each individual project proposal could reach $50,000. He said staff are working to finalize a new fee structure to present to stakeholders in the coming months.

RTEP Language on Track for June MRC Vote

Aaron Berner, PJM's manager of transmission planning, said proposed revisions to the Regional Transmission Expansion Plan process remain on track for a vote at the June Markets and Reliability Committee meeting.

Aaron Berner | © *RTO Insider*

LS Power proposed an amendment in January to Manual 14B that was slated for stakeholder endorsement at the April 25 MRC meeting. The proposal specifies that a transmission owner's supplemental project "will generally be removed from the RTEP" following a final order by a state siting agency rejecting the project. Supplemental projects are proposed by TOs and are not required for compliance with PJM's reliability, operational performance or economic criteria. (See "RTEP Removal Language Vote Deferred Again," *PJM MRC/MC Briefs: April 25, 2019*.)

Berner said PJM asked stakeholders to submit feedback by today so staff can present revised manual language at the May 29 meeting.

Geomagnetic Disturbance Data Needed

PJM wants TOs to submit new or updated data on facilities susceptible to geomagnetic disturbance events as part of its ongoing effort to establish procedures in sync with NERC requirements.

Affected facilities are those that include high-power transformers with a high-side, wye-grounded winding with terminal voltage greater than 200 kV.

PJM wants the TO-supplied data by July 18

Continued on page 32

PJM MIC Briefs

Capacity Interconnection Rights Review Ahead

VALLEY FORGE, Pa. — The PJM Public Power Coalition will draft a problem statement and issue charge that examines capacity interconnection rights in the wake of a new rule permitting the RTO to take them from generators under certain circumstances.

Carl Johnson | © *RTO Insider*

Carl Johnson, representative for the coalition, said his group wants a broader discussion about CIRs and whether the current structure makes sense.

"The reason I want to have a broader conversation is so that we can get to some sort of agreement about what those rights are," he said. "We argue a little about what those rights represent."

The decision came after stakeholders debated whether to revise the existing must-offer exception process problem statement to address CIR relinquishment, or create an entirely new document for approval during Wednesday's Market Implementation Committee meeting. Stakeholders at both the MIC and the Markets and Reliability Committee have expressed concern over a joint plan from PJM and the Independent Market Monitor that revokes CIRs from generators without plans to become Capacity Performance-capable after seeking a must-offer exception. (See *Load Interests Endorse PJM-IMM Must-offer Proposal*.)

The new rule, however, doesn't apply to renewable resources because those generators don't have a must-offer requirement. The Monitor said it will prevent others from "hoarding" CIRs indefinitely.

"All resources should not be able to hoard CIRs," David "Scarp" Scarpignato of Calpine said Wednesday. "If you are going to have a rule like that, it should apply to everyone."

Sharon Midgley | © *RTO Insider*

Sharon Midgley, Exelon's director of wholesale development, argued the conversation can move forward but with its own approved problem statement and issue charge. Exelon lobbied against the mandatory revocation of CIRs during the stakeholder process, including the presentation of its own proposal to do exactly that. Despite earning a majority of MIC support in March, the PJM/IMM plan won out at the April MRC meeting.

PJM's Market Implementation Committee meeting on May 15 | © *RTO Insider*

"They should define the problem and not try to piggyback off this process, which was supposed to deal with a very narrow administrative issue," she said.

PJM Offers Peek at Carbon Pricing Study

PJM's Gary Helm offered stakeholders a *peek* inside the RTO's methodology for its ongoing internal carbon pricing study and said staff chose the social cost of carbon (SCC) as a simulation metric.

Gary Helm | © *RTO Insider*

"We don't care what the price is; we just want a significant price for simulation," Helm said of the choice, noting a number of states have been using the SCC since August 2016. "[The Regional Greenhouse Gas Initiative] is a few dollars, so it's not really impacting dispatch. What if we have a carbon price that is such a level that it impacts dispatch?"

PJM's simulation will observe the impacts of a $52.79/ton price on the market, including cases where prices rise or fall within 25% of that baseline.

Helm said one simulation will divide PJM into a non-carbon zone and a carbon zone — Maryland, Delaware and New Jersey, the three states the RTO expects to be participating in RGGI. Another simulation will measure a regionwide carbon price, ultimately considered the simplest policy to accommodate.

Staff will research the effects of one-way and two-way border adjustments to minimize both environmental and economic leakage between the regions.

Stakeholders Lukewarm on Revisiting Market Seller Offer Cap

As members await a FERC ruling on PJM's market seller offer cap (MSOC), the RTO said it would consider alternative measurements for performance assessment hours (PAHs) — if stakeholders want to revisit negotiations.

The change of heart comes after PJM asked FERC to dismiss the Monitor's complaint that its default MSOC was overstated, arguing that a lack of stakeholder consensus and prior commission approval of CP proved otherwise. (See *PJM: Dismiss Monitor's Offer Cap Complaint*.)

In August, the Monitor concluded that ratepayers were overcharged by $2.7 billion (41.5%) in the 2018 Base Residual Auction because of economic withholding encouraged by the inflated MSOC.

The timespan for measuring performance was changed from PAHs to five-minute performance assessment intervals (PAIs) in compliance with FERC Order 825 in 2018. PJM triggers a PAI when it determines a supply reliability issue exists, providing credits for generators that overperform their capacity commitments and penalties

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for those that underperform.

So far, only one load shed event has occurred within PJM since the CP overhaul in 2015. The event spurred stakeholder action to revise the MSOC calculation, with four proposals failing to garner enough support for inclusion in the Tariff. PJM subsequently dropped the issue, insisting no further investigation was required. (See *Monitor Defends Offer Cap Complaint*.)

Stakeholders, however, expressed a mix of appreciation and hesitation on Wednesday at the offer to reopen negotiations.

"Does PJM believe in its heart of hearts that its answer is where we should be or is PJM open to other constructs?" Johnson said. "If we are just going to have the same conversation we had last year, then I think we are just better letting the complaint play out at FERC."

"We don't want to rehash the stakeholder process and use time to discuss matters that have already been discussed," said Jason Barker of Exelon. "We keep having the conversation go around and around. I think we should get guidance from the commission first."

Monitor Presents Updated 5-Minute Dispatch Problem Statement

The Monitor presented a revised *problem statement* about review processes for real-time security-constrained economic dispatch (RT SCED) and market pricing that PJM uses to send dispatch signals to generators and calculate LMPs.

Siva Josyula | © *RTO Insider*

Siva Josyula of Monitoring Analytics said a publishing price delay on April 8 — as well as a July 10, 2018, low area control error (ACE) *event* and corresponding Manual 11 revisions — call into question the transparency of PJM's RT SCED processes.

The Monitor added work activities to the *issue charge* that ask the MIC to review the triggers for price-bounding violations and the timeline of publishing LMPs, as well as potential updates to LMP thresholds and procedures for validation checks and publishing prices. Stakeholders must also identify metrics for operator actions, including — but not limited to — biasing in the intermediate-term SCED, RT SCED and locational price calculator.

Double Payments Extend Beyond Fast-start

Adam Keech, executive director of PJM's market operations, said a recent FERC order saying that current accounting practices provide double payments to fast-start resources puts the RTO in a difficult position.

Adam Keech | © *RTO Insider*

"The issue is more of a day-ahead uplift issue," he said. "We are left in this issue of how do we address it. If we just apply it to fast-start, it could be conceived as discriminatory. If we apply it everywhere else, it could be out of scope."

The problem arises when PJM pays a generator for uplift in the day-ahead market but then dispatches that same resource in real time at a higher commitment. The generator has the ability to recover uplift costs PJM already paid it for a day earlier — except the issue is far broader than just fast-start resources.

Keech presented the issue as the first of several MIC educational sessions about the impacts of FERC's recent order on the RTO's fast-start pricing rules. (See *FERC Orders Fast-start Rules for NYISO, PJM*.) The RTO loses "tens of millions" annually on double payments — a relatively small problem by PJM's standards, he said.

FERC wants PJM to address this matter in a compliance filing due July 31, as well as an informational report due Aug. 30 about how the new rules don't raise market power concerns. ■

— Christen Smith

PJM PC/TEAC Briefs

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so that further analysis can be completed in 2020.

Dominion Supplementals

Dominion Energy submitted requests for supplemental *projects* during Thursday's Transmission Expansion Advisory Committee meeting.

A Dominion customer wants to add a third 84-MVA distribution transformer at the Enterprise Substation in Loudoun County, Va. The new transformer is being driven by continued data center load growth and alternate feed contract reservations, with a requested in-service date of July 15, 2020.

In the same county, Dominion wants to add a fourth 84-MVA distribution transformer at the Poland Road Substation. The need is driven by continued load growth in the area and contingency loading for the loss of one of the existing transformers, with a requested in-service date of Dec. 31, 2021.

In Prince William County, Dominion requested a new substation to support a data center campus with a total load in excess of 100 MW, with a requested in-service date of Dec. 15, 2021.

Dominion also presented nine proposed solutions for requested supplementals at a total cost of $104.25 million.

American Electric Power Solution

American Electric Power presented a *solution* to one of its proposed supplemental projects for the Tanners Creek line in Indiana on Thursday.

AEP wants to spend $5.93 million installing two new 345-kV breakers to address faults on the connecting Dearborn line. A crew will move the existing M2 breaker into a new N string, allowing for the termination of the Dearborn line. A new 345-kV breaker will complete the T string.

Alternative solutions include reterminating the 345/138-kV transformer and 345-kV Dearborn line into existing breaker spots. Because of the way the station is laid out, this would require reconfiguring multiple 345-kV lines and would cost more, AEP said.

Protection Standards Revisions Endorsed

Stakeholders unanimously endorsed editorial *changes* to Manual 7: PJM Protection Standards.

The revisions reflect industry standard updates from the Institute of Electrical and Electronics Engineers and will apply to all new projects approved after Jan. 1, 2012. ■

— Christen Smith

Gens Back PJM Pricing Proposal; Md., IMM Oppose

Continued from page 1

reserve capability by inflating load forecasts. "These practices are so pervasive that, without them, PJM would have been in a reserve shortage in almost one-third of five-minute intervals in 2018," Exelon said.

The company filed an affidavit by NorthBridge Group consultant Michael Schnitzer, who said PJM's estimate of $556 million in additional annual payments by load is misleading, because it only measures the impact of the proposal on market prices and energy and reserve procurement volumes.

Schnitzer estimated PJM's proposal "would create at least $200 million of net benefits by both increasing reliability through incremental reserve purchases and by reducing production costs," Exelon continued. "PJM's proposal is therefore the rare market reform that both creates incremental reliability benefits while simultaneously reducing total costs."

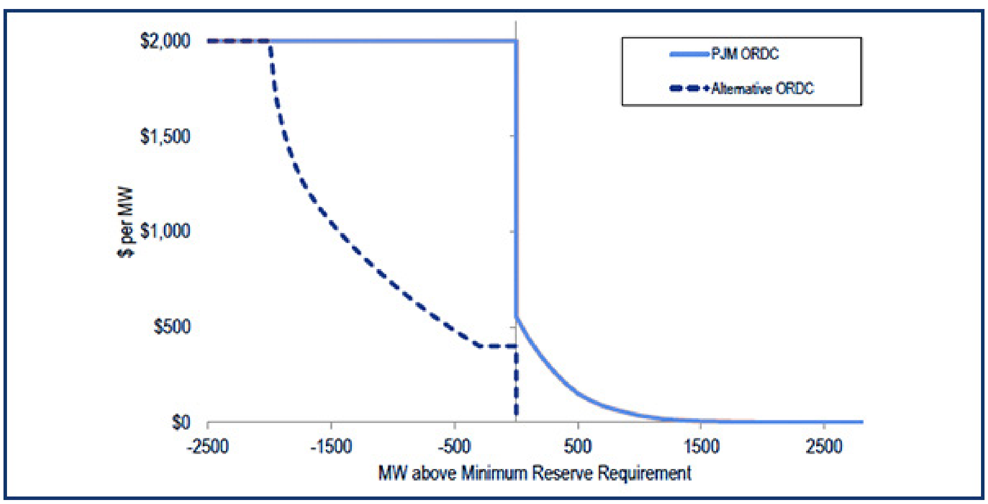
"PJM's proposal is therefore the rare market reform that both creates incremental reliability benefits while simultaneously reducing total costs."

– NorthBridge Group consultant Michael Schnitzer

NEI said PJM operators' "load biasing" has contributed to the financial pressures facing nuclear plants.

"Over the course of the entire year, the average operator bias was 515 MW of out-of-market additions. PJM's filing makes clear that this bias is a natural result of the asymmetric incentives facing operators. The consequence of failing to have sufficient reserves could be calamitous, whereas the downside of excess procurement can be rationalized as just a small instance of market price suppression," NEI said. "Given the scale and frequency of these biases, however, the cumulative effect is quite large."

AWEA and SEIA agreed with PJM that the lack of alignment between the RTO's day-ahead and real-time markets is unjust and unreasonable and that reforms are needed to provide the flexibility needed to respond to the increase in variable generation. "As explained by PJM, 'every other [RTO] has a methodology to procure the reserve products needed in real time in advance of the operating day except PJM.'"



PJM's Independent Market Monitor said FERC should reject the RTO's proposed operating reserve demand curve (ORDC) in favor of the Monitor's plan (dotted blue line), which prices reserves beyond requirements at $0. | *Monitoring Analytics*

More Action Sought

FirstEnergy said the RTO's proposal was so "watered down" it will fail to create the "meaningful price impact that is needed to spur increased investor confidence in the PJM wholesale markets."

In addition to approving PJM's proposal, FirstEnergy said FERC should order the RTO "to conduct a holistic review of all of PJM's wholesale markets to ensure that generation resources that provide key attributes, such as fuel security, fuel diversity and resilience, receive compensation for the attributes they provide to the electric grid."

The eight energy trading firms, members of the *Energy Trading Institute*, backed PJM's proposal but said it represents only "low hanging fruit" and that the RTO should take further action to fix its energy market.

"To be clear, ETI is not advocating for an energy-only construct, but both PJM staff and its stakeholders should focus on getting the prices right in the energy market and not on continual and Sisyphean revising of the capacity market constructs to meet newly arising needs," the traders said. "The capacity markets were intended to be residual markets, not a panacea for all revenue needs."

Former Montana regulator Travis Kavulla, director of energy policy for the R Street Institute, said the PJM proposal is "laudable" but may not be just and reasonable without also making changes to the capacity market. "It is not clear why consumers, having paid for capacity once through the forward capacity market, should be expected to pay again for a type of operational capacity in near real time," Kavulla said. "The commission should make clear that a market design shaped around an increasingly robust ORDC is an off-ramp from, and an eventual substitute for, the forward capacity market, which is an inferior vehicle to pay resources for the capacity that customers actually require."

Kavulla noted that PJM's base case projects energy and capacity revenues will increase by $556 million annually while production costs rise only $30 million. "In other words, the vast majority of ORDC revenue is paying for resources' fixed costs and not the costs associated with production under this new market design. At the same time, avoided uplift costs — one of the core reasons to adopt ORDC that PJM proffers, with which we agree — amount to little more than $3 million.

PJM News

"An ORDC with high price caps remains administrative in nature, but at least its administrative elements seek to correct blunter and worse administrative interventions in the markets — namely operator commitments and lower price caps," Kavulla continued. "Importantly, ORDC does not require the degree of speculative planning that forward capacity markets do. Either a resource has dispatchable headroom in near real time, or it does not."

Insufficient Evidence

The Monitor and the Maryland Public Service Commission said PJM's proposal is overly expensive and not supported by evidence that current rules are unjust and unreasonable.

"PJM's proposal, if implemented, would cost ratepayers billions of dollars with no commensurate benefits," the PSC said. "Furthermore, energy and operating reserve market revenues would increase without an appropriate offset in the capacity market, thereby resulting in billions of dollars in over-recovery."

The PSC said the real problem is that PJM's dispatchers lack appropriate tools and generator operating information.

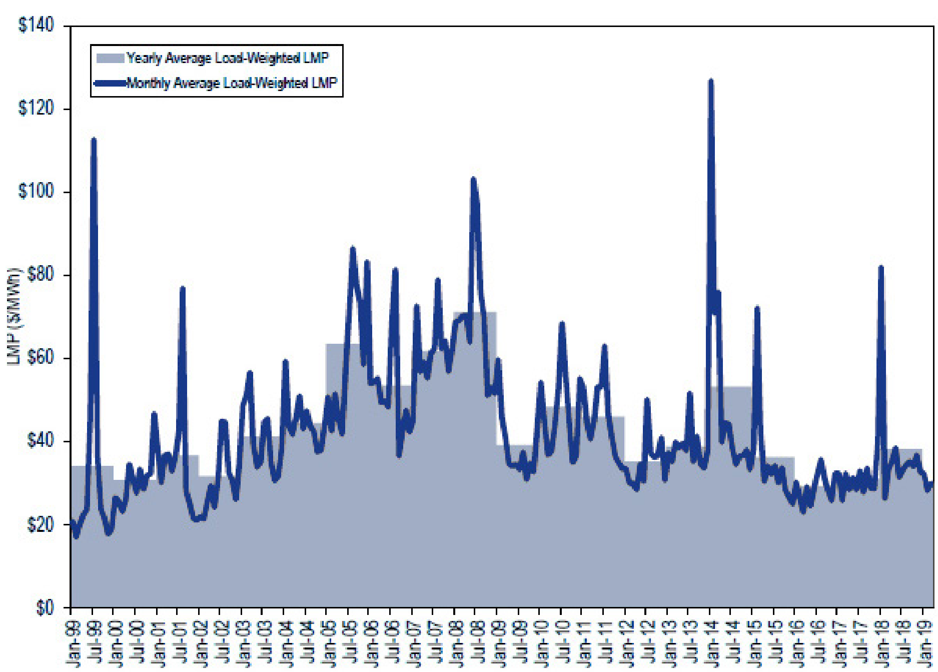
"It is vexing that after seven years of market implementation and in this modern age of technology, communications and telemetry, PJM is unable to provide its dispatchers with actual, real-time resource operating data and performance capabilities from the generators it controls on its system," the PSC said.

The PSC challenged PJM's proposal to increase maximum prices — including compounding of multiple reserve products — to $12,000/MWh, saying the RTO's current maximum of $3,700 is "on par" with the $3,725/MWh cap in NYISO and the $3,500/MWh maximum in MISO.

"While an overreliance on wind and solar resources during times of operational stress may merit additional review in the future, such resources currently contribute minimally to the PJM grid," the PSC said. "For example, PJM indicates that when the system experienced its peak demand during the most severe recent cold weather event, wind and solar resources amounted to approximately 1.4% of the total generation output."

Public Citizen also opposed the filing, saying it is "simply a regional version of U.S. Energy Secretary Rick Perry's grid resilience bailout push."

"PJM is run less as an independent transmission operator and more as a price-fixing cartel: PJM management is free to conspire with certain of its powerful members, promoting pricing changes designed to deliver bigger profits to said members," the group said.



The IMM rejected PJM's claims that prices during the January 2019 cold snap were too low, saying there was ample supply, generator outage rates were low and natural gas prices remained below the cost of fuel oil. | *Monitoring Analytics*

FirstEnergy said the RTO's proposal was so "watered down" it will fail to create the "meaningful price impact that is needed to spur increased investor confidence in the PJM wholesale markets."

It said FERC should order an evidentiary hearing to investigate "the cabal involving PJM management and certain transmission owner-members that control generation assets." It also said Commissioner Bernard McNamee, a former Department of Energy official, should recuse himself from the case.

Monitor: Prices Reflect Oversupply

The Monitor said PJM's current energy and ancillary service markets are producing just and reasonable rates and that the RTO's proposal would increase costs by more than $1.7 billion per year.

The proposal "shifts scarcity revenues from the capacity market to the energy market but does not propose that capacity market revenues reflect that shift," the Monitor added.

It rejected complaints that energy and reserve prices are too low, saying they are a function of cheap fuel and excess capacity, noting the RTO's reserve margin — 25.9% in June — is 62% above the required 16% margin.

"Frequent reserve pricing at zero is just and reasonable because it is an efficient, competitive outcome. This market design and market outcome is common among the RTOs. Finding it unjust and unreasonable in the PJM market would naturally extend to the other RTO markets."

If the commission does rule PJM's current rules unjust, the Monitor said FERC should reject the RTO's plan in favor of its own proposal, which was the most popular of five voted on by the Markets and Reliability Committee in January — albeit at 52%, still below the two-thirds threshold needed for endorsement. (See *PJM Stakeholders Deadlock on Energy Price Formation*.) ■

PJM News

Protesters Doubt PJM Cost Analysis of Transource Alternative

By Christen Smith

Landowners united against a proposed transmission project straddling the Pennsylvania-Maryland border said on Monday they doubt an alternate plan using existing lines may cost an extra $94 million, as PJM suggests.

"I don't see how that's possible that by using existing infrastructure that it could be more expensive," said Barron Shaw, spokesperson for Citizens to Stop Transource. "It's hard to understand."

Shaw's group includes residents from Pennsylvania's York and Franklin counties and Maryland's Harford County, where Transource Energy plans to construct two 230-kV double-circuit lines totaling about 42 miles, known as the Independence Energy Connection (IEC) project. PJM selected the $372 million proposal — its largest market efficiency project to date — during the 2013/14 long-term planning window to address congestion in the AP South interface and has five times since reviewed its benefits to the grid, determining in each round that the IEC remains the most effective way to reduce load costs.

In *testimony* submitted to the Maryland Public Service Commission on May 8, PJM's Tim Horger said the RTO's most recent analysis, completed in February, determined the IEC would generate a $931 million reduction in congestion costs over the next 15 years, with a benefit-cost ratio of 2.17 — well above PJM's 1.25 threshold required for inclusion in its Regional Transmission Expansion Plan.

Protesters argue, however, that the need for the eastern segment of the project could be met by the existing Furnace Run-Conastone and Furnace Run-Graceton 230-kV double-circuit transmission tower lines, which each have only one 230-kV circuit and could carry a second. Maryland's Power Plant Research Program (PPRP) urged the PSC to suspend the project while PJM studied the market efficiency of this alternative and three others — a request that was granted in January. (See *More Info Needed on Tx Line Options, MD PSC Says* and *Cancel Transource Line, Md. Panel Says*.)

As requested, PJM analyzed PPRP's four conceptual alternatives and determined all but its third option — adding lines to the Furnace Run-Conastone towers — created thermal violations too costly to even consider for its RTEP. Even still, to help the remaining plan survive its market efficiency process, PJM and Transource expanded the scope to add a third transformer at the Furnace Run station that would alleviate possible reliability violations. This modified plan was called 3A in PJM's testimony.

Steve Herling, PJM's vice president of transmission planning, said in testimony that the additional transformer caused the Peach Bottom-to-Furnace Run 500-kV lines to reach 98.5% of its thermal conductor limit following a single contingency. Conversely, the IEC takes significant power load off that line, Herling said, calling into question the viability of the proposed configuration in 3A.

PJM's analysis showed 3A would cost between $54 million and $94 million more than IEC and produce $267 million less in congestion benefits to the region. Its benefit-cost ratio ranges from 1.39 to 1.52, still well above PJM's 1.25 threshold but lagging far behind the IEC's rating.

Herling said none of the conceptual alternatives proved "demonstrably superior" or even equal to the IEC plan. Jeff Shields, PJM spokesman, said Monday that staff stand by their testimony.

PSC hearings on the project begin in Maryland on June 3. Meanwhile, an administrative law judge in Pennsylvania will consider the IEC's reliability benefits after the state Public Utility Commission overturned a prior dismissal of PJM testimony regarding the issue.

PPRP has described PJM's attempt to justify the project on reliability grounds as a "bait and switch." Although the project was not needed to address reliability violations when it was approved, the RTO said "that the project would inherently enhance system reliability by introducing additional transmission network paths."

"Reliability means generator-deliverability reliability," Shaw said. "It's not about keeping people's lights on." ■

Once referred to as the AP South Congestion Improvement Project, Transource's Independence Energy Connection project would consist of two lines. The western portion would run from the Ringgold substation in Maryland to the Rice substation in Pennsylvania. The eastern line would run from the Conastone station in Maryland to the Furnace Run station in Pennsylvania. | *Transource*

SPP News

SPP Western Reliability Briefs

SPP's MOP 'Cleans Up Stuff'

GOLDEN, Colo. — SPP staff last week shared a proposed "modification oversight process" with its Western reliability coordination customers, much to the glee of those involved.

Given the industry's fondness for acronyms, there's always room for one more: The process was tagged as "MOP."

"Mop it up!" advised SPP Operations Vice President Bruce Rew as staffer Clint Savoy prepared to explain the process during a Friday conference call with the Western Reliability Executive Committee (WREC).

"That's what we use to clean up stuff," Savoy said.

MOP actually borrows from SPP's existing revision-request process to provide a means of managing document modifications (modification responses, or MRs) related to the RTO's Western RC services. Savoy said it applies to documentation established by SPP or its working groups that might affect operations or have a compliance or financial impact on its Western RC services customers.

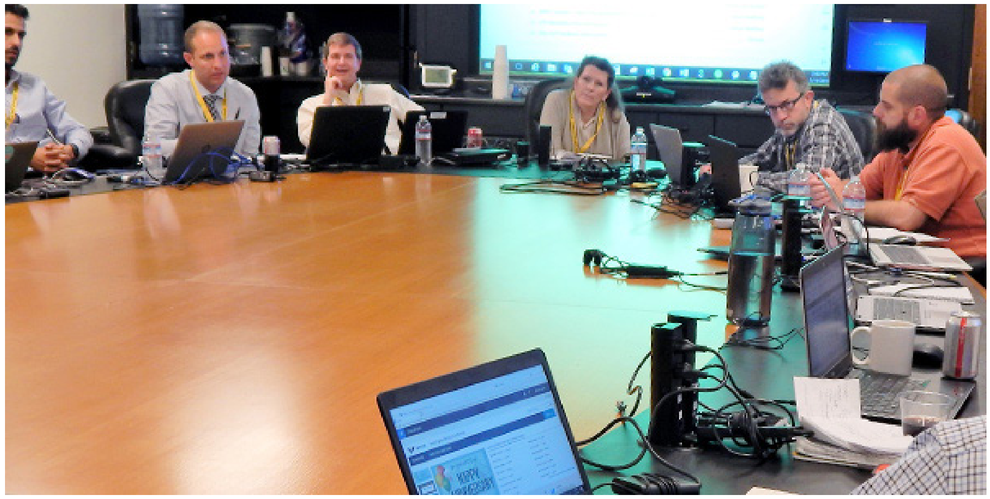
"MRs identify which governing document or specific section requires a review and approval, and by which groups," Savoy explained.

The process establishes submission timelines, how to submit and respond to comments, and guidelines for public posting. MOP incorporates the impact analysis and recommendation reports familiar to SPP's Eastern members.

SPP said in September it had signed contracts to provide RC services to balancing authorities representing about 12% of Western Interconnection load, effective Dec. 3. Peak Reliability, which has been the West's RC since 2011, is winding down operations by the end of the year. (See *CAISO RC Wins Most of the West*.)

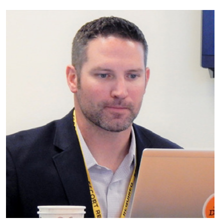
The Western Reliability Working Group (WRWG), which reports to the WREC, debated the MOP during a May 14-15 meeting in the Rocky Mountains' foothills. As the primary — and currently only — SPP working group in the West, the WRWG will be responsible for taking one of five actions on any MR: approve, reject, table, withdraw or refer.

The WREC will be the final authority and can take the same five actions, the lone exception being remanding — rather than referring — an MR back to the working group.



The SPP Western Reliability Working Group gathers in Golden, Colo. | © *RTO Insider*

The WRWG was unable to reach consensus on whether the executive committee should see every MR the working group approves or just those that aren't unanimous. Members were also unable to agree on how the WREC would revise an approved MR.



WRWG Chair Denton McGregor | © *RTO Insider*

"My concern with the process is the time consideration," said Black Hills Energy's Denton McGregor, the WRWG chair. "But with 40 [stakeholder] groups in the East, SPP seems to be managing [the process]."

The WREC discussed the same issues during its conference call before voting to require that all items needing approval be sent to the committee. Its members also agreed they should provide guidance when remanding MRs back to the WRWG.

"We should tell them exactly what were the concerns that led to the turndown," Rew said.

"I believe the WREC exists for a reason," said WREC Chair Keith Carman, of Tri-State Generation and Transmission. "We don't need a strong hand of approval, but simply having these items come to us provides value. It gives us the ability to be aware of things that are changing."

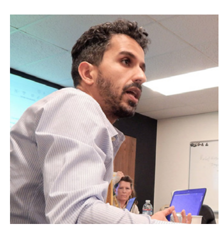
The MOP has yet to be approved. SPP is still gathering comments from Western entities with plans to gain the WRWG's approval in June. Savoy is scheduled to bring a final version for approval to the WREC in July.

RC Still Needs Data-sharing Agreement

Lack of a final data-sharing agreement appears to be the lone sticking point in SPP's plans to extend RC services into the West.

Peak currently operates under a universal data-sharing agreement (UDSA) that gives operating entities access to key data necessary for reliable system operations and meets NERC standards. CAISO has used that agreement and revised it to create a Western Interconnection Data Sharing Agreement (WIDSA) that it will use moving forward, SPP staff said.

SPP conducts its business in the East under NERC's operating reliability data (ORD) confidentiality agreement. It has worked with CAISO to add language to the WIDSA that allows non-signatories to see some of the data but hopes to have everything resolved before shadow operations start in October.



SPP's Yasser Bahbaz explains the West's different data-sharing agreements. | © *RTO Insider*

SPP's Yasser Bahbaz said the WIDSA acknowledges the ORD. "We're in a much better place than we were two months ago," he said.

Elsewhere, SPP remains on track to meet the go-live date with progress on a several fronts:

SPP News

- The Congestion Management and Seams Task Force, one of three groups reporting to the WRWG, is developing a congestion management methodology that CAISO "can agree to as well," Tri-State's Michael Houglum said. "We're getting close to this," he said. "It's already so much better than what we used to have [with Peak]."
- SPP staff are testing its custom R-Comm messaging system with the Grid Messaging System (GMS) used by the Western Interconnection's other RC providers (the Alberta Electric System Operator, BC Hydro, Gridforce and CAISO). SPP and CAISO have also created a *communication protocol* whereby neighboring balancing authorities and transmission owners that lie across the seam can send messages using GMS or R-Comm, depending on their RC. SPP is also setting up an application programming interface (API) that will further enable messaging with CAISO.
- Staff said SPP will register as SPPW in the North American Energy Standards Board's electric industry registry (EIR), effective Dec. 3. This will require SPP's Western RC entities to designate the RTO as their RC before Dec. 21, when Peak plans to pull its EIR registration. Software developer OATI administers the web-based tool, which collects e-tags from registered entities that feed into the unscheduled flow mitigation plan.
- SPP has completed site visits with all the Western entities, helping increase the RTO's familiarity with the region. "It gives us an appreciation for how they do things in the West," Bahbaz said. The RTO will welcome visitors to its Little Rock, Ark., headquarters in the fall.
- An East-West system model is expected to go into production in July using a Western model based on a Peak model published earlier this year.
- SPP has been holding monthly calls with training representatives in the Western footprint. Operator training begins in September. Staff are discussing with CAISO restoration training in 2020.

Three major deadlines loom: the Sept. 1 completion of on-site RC certification, the Oct. 1 commencement of shadow operations with adjacent RCs and the Dec. 3 go-live to begin providing RC services.

SPP's Reliability Plan Confidential, but…

Bahbaz told the WRWG that SPP's reliability plan includes both its Eastern and Western footprints and should "hopefully meet the need of anyone interested in SPP procedures."

However, those interested in SPP procedures will have to travel to Little Rock to view the plan.

"The plan has steps specific to SPP's system, and SPP believes those are confidential to SPP," Bahbaz said. "We will show the procedures to anyone who comes to [our] control room."

"We can follow directions just fine," Houglum said. "It helps everybody's knowledge if we understand why you're asking us to do certain things in certain instances. Any background information we have allows us to execute those decisions better."

Working Group Revises its Charter

The WRWG made several changes to its charter, adding clarity to term limits for the group's leadership and its voting structure.

Black Hills' Denton McGregor and SPP's Clint Savoy share a light moment. | © *RTO Insider*

Members agreed to limit the chair and vice chair to two-year terms, with the initial term beginning in January 2019. Elections will be held at the end of the calendar year. Should one of the positions become vacant before the term expires, a special election will be conducted during the next regularly scheduled meeting.

The WRWG also revised the charter to include the use of a simple majority (greater than but not equal to 50%) of those present and voting to determine motion outcomes.

"SPP wants engagement," McGregor said. "You need to be present and take part if you want your voice heard."

Other charter revisions eliminated the need to reach a unanimous decision before requesting feedback from the WREC and added the ability to review and approve or reject revisions to applicable documents in accordance with the MOP, and to provide recommendations and escalate to the WREC items requiring financial consideration.

WRWG Members: Coordinating Communication Helpful

Working group members found the discussion beneficial, even if they did spend considerable time trying to determine whether abstentions count against a unanimous vote. "An abstention is not a vote," said Colorado Springs Utilities' Warren Rust, stating the group's consensus position.

"This is all related to coordinating and communicating activities," McGregor said. "There are a lot of moving parts and pieces to everything, not just with SPP, but here in the West. This keeps us informed."

"Oh yes, this is helpful, just having come and hearing the discussion," said Linda Jacobson-Quinn of Farmington Electric Utility System in New Mexico. "It's the good old theory that if there were no communication at all, we wouldn't be able to build the things we need in order to ensure reliability."

Savoy, SPP's senior interregional coordinator, said the RTO's significant progress in offering RC services to the West is "a direct result of the engagement of stakeholder groups."

"I think the representatives all agree that our collective success is dependent on solidifying relationships and promoting collaboration between entities," he said. "That's where SPP believes we provide significant value to our stakeholders." ■

— Tom Kleckner

SPP News

DC Circuit Again Rejects MRES Appeal

By Tom Kleckner

The D.C. Circuit Court of Appeals last week rejected rehearing requests from Missouri River Energy Services (MRES) following the court's earlier determination that SPP could charge the utility for certain transmission fees (*18-1166*).

The court denied MRES' request for rehearing by the panel that issued the March ruling or a rehearing en banc. The utility group had asked the court to review FERC's 2017 order rejecting a request that MRES and other SPP members be exempted from congestion and marginal loss charges under a grandfathered contract signed before they joined the RTO. (See *FERC Rejects 'Carve-Out' from SPP Congestion, Loss Charges*.)

MRES, an organization of 61 municipal utilities in the upper Midwest, appealed the ruling, saying the court had committed multiple errors in its decision. It said the opinion "directly conflicts" with a 2007 decision by the court involving Wisconsin Public Power and FERC.

In that case, "FERC agreed with [MISO] that imposing significant changes in scheduling practices between parties to pre-existing agreements would amount to 'significant changes' … affect[ing] the bargain between the parties,'" MRES said in its appeal.

Quoting the 2007 panel, the organization said, "Not carving out this narrow class of [grandfathered agreements] would modify them, thereby triggering application of *Mobile-Sierra*'s public interest standard."

In rejecting MRES' original argument in March, the court said SPP "did not seek to impose congestion and marginal loss charges on the 1977 reservation until Missouri River subsequently came within the pool's footprint."

FERC in 2017 ruled that the SPP members were ineligible for "carve-out treatment" under the SPP Tariff and a 1977 transmission service contract between Nebraska Public Power District and Basin Electric Power Cooperative.

The 1977 contract arose from construction of NPPD transmission needed to deliver power to the Western Area Power Administration's Upper Great Plains region and Lincoln Electric System from the Missouri Basin Power Project — a venture owned by six public power and cooperative utilities that includes the 1,710-MW Laramie River coal-fired generator, the Grayrocks Dam and reservoir, and more than 500 miles of extra-high-voltage transmission. ■

Laramie River Station | *Burns & McDonnell*

Company Briefs

ISO-NE Expects Sufficient Power Supplies for Summer

ISO new england

ISO-NE said the region is expected to have sufficient resources to meet peak consumer demand for electricity this summer under both typical and extreme weather conditions.

The RTO said this summer, under typical weather conditions, electricity demand is forecasted to peak at 25,323 MW. Extreme summer weather (extended heat waves) could push demand up to 27,212 MW. Still, more than 32,000 MW are expected to be available to consumer demand.

More: *ISO-NE*

Utilities Charging Customers for Coal Clean-up Face Blowback

Officials from Virginia to North Carolina to South Carolina are pushing back on utilities' plans to charge customers for the costs of shuttering coal ash ponds, long the primary way of storing residue from burning the fuel.

In a potential blow to Dominion Energy, Virginia State Corporation Commission staff expressed concerns in a filing released last week over the company's bid to recover as much as $247 million through monthly bills for cleanup efforts. Dominion is asking for permission to charge customers the cost of a landfill, sedimentation ponds and water treatment facilities that it built at an existing coal plant in 2015.

Duke Energy in particular would take a big hit as the utility is estimating costs of as much as $10.6 billion in the Carolinas. Officials there are already challenging more than a half-billion dollars.

More: *Bloomberg*

Disney Could Still Build Nuke After Fla. Bill Fails

A bill before Florida lawmakers that would have revoked Walt Disney World Resort's ability to build a nuclear power plant died when the session ended this month.

A 1967 state law has always allowed Disney to construct a nuclear power plant, however unlikely it was that Disney World would ever actually try to use it. But instead of an expensive nuclear plant — plans for a small one might start at $1 billion and then run up to $10 billion — Disney is pursing

a vastly different option: massive, nearby solar farms. The company last month began operating a 270-acre, 50-MW solar farm facility that's roughly twice the size of the Magic Kingdom.

More: *Orlando Sentinel*

Reuters: Tesla's Solar Factory Exporting Most of its Cells

The "great majority" of solar cells being produced at Tesla's factory in upstate New York are being sold overseas instead of being used in the company's trademark "Solar Roof" as originally intended, according to documents reviewed by Reuters.

The exporting underscores the depth of Tesla's troubles in the U.S. solar business, which the electric car maker entered in 2016 with its controversial $2.6 billion purchase of SolarCity.

Tesla has only sporadically purchased solar cells produced by its partner in the factory, Panasonic, according to a Buffalo solar factory employee speaking on condition of anonymity. The rest are going largely to foreign buyers, according to a Panasonic letter to U.S. Customs and Border Protection officials reviewed by Reuters.

More: *Reuters*

Federal Briefs

House Bill Would Gut Funding for Yucca Mountain

The House Appropriations Committee's Subcommittee on Energy and Water Development last week voted to approve an energy spending bill that cuts funding to revive the development of Yucca Mountain as a nuclear waste storage site in a step that sets up a likely battle between the House of Representatives and the Senate over the project.

The subcommittee approved the $46.4 billion legislation for energy and water development programs without the proposed $116 million in President Trump's budget for Yucca Mountain.

The full committee will consider the bill today.

More: *Las Vegas Review-Journal*

IG: EPA Should Recoup Pruitt's 'Excessive' Travel Costs

EPA's inspector general last week identified nearly $124,000 in "excessive" travel costs for former Administrator Scott Pruitt during 2017, but the agency said it had no plans to try to recoup the money.

The long-awaited report by the agency's watchdog pointed to Pruitt's practice of fly-

Pruitt at the Vatican in June 2017 | *EPA*

ing in first class, often with a bodyguard, as the main reason for the excessive costs, and said the travel — which totaled $985,000 over a 10-month period — was often improperly approved. And it recommended EPA consider trying to claw back the excessive portion of that spending.

The agency said Pruitt's first-class expenses were justified because other travelers were confronting him in airports during his trips. However, the IG said EPA "lacked sufficient justification to support endangerment of the former administrator's life."

More: *Politico*

DOE Working with Colstrip Owners to Keep Plant Open

The Department of Energy is working with the owners of the troubled Colstrip Power Plant to extend the life of the facility, according to Steven Winberg, assistant secretary on fossil fuel energy.

Speaking before the Senate Energy and Natural Resources Committee, Winberg told Sen. **Steve Daines** (R-Mont.) about plans

to pipe carbon dioxide from the power plant to an oil play in southeast Montana.

"We're happy work with Colstrip to see what opportunities there are to keep the plant open and reduce its emissions and provide a value stream for enhanced oil recovery," Winberg said.

More: *Billings Gazette*

Mnuchin Says Carbon Capture Tax Credit Guidance Coming Soon

Treasury Secretary **Steven Mnuchin** last week said he hopes to soon roll out interim guidance on a tax credit for companies that capture their carbon pollution.

Pressed by Sen. Chris Coons (D-Del.), who called the tax credit critical for the emerging technology, Mnuchin told a Senate Appropriations subcommittee he hopes to have guidance out shortly but resisted giving a firm deadline. "I share your view this is very important," Mnuchin said. "We are taking it very seriously and I hope we get it out soon."

Legislators directed the IRS to offer the tax credit as part of the 2018 budget bill. But senators have been frustrated by the pace to offer them to the power plants and energy companies that would benefit.

More: *The Hill*

State Briefs

MAINE

CMP: Bill to Create Consumer-owned Utility Amounts to 'Hostile Takeover'

A bill that would create a consumer-owned power company to "restore local ownership and control of Maine's power delivery systems" received strong support from disgruntled ratepayers at a public hearing last week but was challenged by Central Maine Power as a constitutionally questionable proposal that would reduce grid investment and reliability.

Following the hearing on LD 1646, CMP President and CEO Doug Herling issued a statement that left no uncertainty about the state's largest electric utility's stance on the bill.

"The Maine Power Delivery Authority bill, LD 1646, proposes to seize private company assets that are not for sale and put them into the public domain; there are serious constitutional questions about this proposal and the business community should be concerned about this precedent," Herling stated. "Maine people should also question how a public body can dedicate the necessary investment and the daily operating knowledge to manage electric service in Maine."

More: *Mainebiz*

MINNESOTA

PUC Approves Agreements for Xcel to Service to Google Data Center

The Public Utilities Commission last week approved agreements for Xcel Energy to provide electric service to a proposed new Google data center.

The commission approved several electric service agreements and related ratemaking treatments submitted by Xcel. The data center would be owned and operated by Honeycrisp Power, an affiliate of Google. The facility would be located in Becker on property adjacent to Xcel's Sherco coal plants.

The PUC found that the proposals by Xcel are in the public interest because of the economic development and jobs associated with the project, both locally and across the state. The addition of Google as a customer will help enable Xcel to meet its revenue requirements without raising its rates.

More: *Daily Energy Insider*

NEVADA

Bill Would Severely Curtail Ability of Businesses to Leave NV Energy

State Sen. Chris Brooks (D) last week introduced a bill that would add numerous new restrictions and requirements for businesses that already have or are in the process of departing NV Energy's electric service.

The bill would now require any business applying to leave the utility prove that such an exit would be "in the public interest." Current law allows large customers to file an application with the Public Utilities Commission to obtain power from another source, as long as it is determined the exit isn't contrary to public benefit and the departing business pays an "impact" fee to offset any financial burden that other customers would pay.

Under the bill, exits would be much more limited and require several more steps before they take place. It would require NV Energy to include in its integrated resource plan the total amount of energy that departed customers can purchase from outside providers.

More: *The Nevada Independent*

NEW JERSEY

BPU Going to Court over $300M Nuclear Bailout

The Board of Public Utilities is going in front of a court over hundreds of millions a year in ratepayer subsidies it approved for Public Service Enterprise Group last month.

The Rate Counsel last week filed an appeal of the board's decision to award PSEG $900 million over three years. The appeal will be

heard in the state Superior Court's Appellate Division.

PSEG said it needed the hefty subsidy, paid for by an increase in people's electric bills, or else it would close its three nuclear units in Salem County. But that assessment was disputed by the Rate Counsel and the PJM Independent Market Monitor, which reviewed PSEG's financial statements and argued the firm did not need support from residents to stop its nuclear units from shuttering.

More: *Press of Atlantic City*

NEW MEXICO

PRC Unanimously Rejects Rehearing on PNM Tx Line for Facebook

The Public Regulation Commission unanimously rejected motions to reconsider a decision to charge Facebook nearly half the cost of a new $85 million transmission line.

Public Service Company of New Mexico and two other intervenors had asked the five-member commission to reconsider its mid-April decision, which said PNM could not charge general ratepayers anything for building the transmission line because the utility had said the line would only serve a new Facebook data center. However, PNM has since corrected its testimony, calling the line a "network upgrade" that benefits both wholesale and retail customers.

But the commission rejected those motions at its open meeting last week. It said PNM and the other parties did not explicitly ask to reopen the case record for new evidence to be entered through a formal rehearing, forcing it to rely on existing evidence in the record. PNM could appeal to the state Supreme Court.

More: *Albuquerque Journal*

NEW YORK

DEC Rejects Williams Pipeline

The Department of Environmental Conservation last week rejected Williams Co.'s application to construct a nearly $1 billion, 37-mile natural gas pipeline through the state.

The Northeast Pipeline Enhancement is intended to expand the existing Transco natural gas pipeline system. It would run entirely underwater, with 23.5 miles through the New York Bay.

In a statement announcing its decision, the department noted that it had received comments from more than 45,000 people about the project, 90% of whom opposed it. It said that construction would contaminate waters with mercury and copper.

More: *The New York Times*

OKLAHOMA

OCC Approves OG&E's Plant Acquisition Plan

The Corporation Commission last week approved Oklahoma Gas and Electric's plan to spend about $27 million to acquire a 360-MW coal-fired plant owned by AES Shady Point. The plan also authorizes OGE to spend $26 million to buy a 146-MW natural gas-fired, combined cycle plant owned by Oklahoma Cogeneration.

The commission issued the order after spending a couple of hours hearing arguments about the competitive bidding process the utility used to make its selections and about a rate adjustment connected to its plan. The order won't allow OGE to begin recovering costs until a pending rate case is settled.

While the deal does affect customers' bills, utility officials said customers won't see an increase. They said the costs to acquire the plants is less than what OGE had been paying each for power under previously existing power purchase agreements, noting they expect customers will save at least $40 million each of the next three years.

More: *The Oklahoman*

SOUTH DAKOTA

NorthWestern Suggests $6.5M Rate Increase, down from $34.8M

NorthWestern Energy customers would see a $6.5 million rate increase under a proposed settlement between the utility and opponents to its billing plans. The increase is down from the $34.8 million originally sought by the utility.

For months, the utility has argued that it needed to raise rates $34.8 million ($76.44 per residential customer per year). In February, the Public Utilities Commission agreed that NorthWestern could increase its rates by $10 million in the interim while the remaining $24.8 million would being considered. The $10 million rate hike already approved would be walked back as part of the settlement.

The settlement agreement also preserves a 10% return on equity for NorthWestern's 30% ownership share of Colstrip Power Plant.

More: *Billings Gazette*

Otter Tail Power on Road to Increase Rates

The Public Utilities Commission approved a return on equity rate for Otter Tail Power that will allow the company to increase base rates charged to its customers.

The PUC approved an 8.75% ROE. Otter Tail argued for 10%, while PUC staff recommended 8.25%. The action comes after an analysis of Otter Tail's request to increase customer base rates to generate about $6 million in additional revenue. The final revenue requirement is expected to be presented by Otter Tail and PUC staff for approval on May 28.

More: *Capjournal Bureau*

WISCONSIN

MGE Targets Carbon-neutral Electricity by 2050

Madison Gas & Electric last week set a goal to eventually eliminate or offset all carbon emissions, joining a handful of investor-owned utilities that have committed to full decarbonization by 2050.

CEO Jeff Keebler said MGE's future requires "ambitious and critical reductions" in carbon that align with scientific recommendations for limiting global warming. He said the goal will require technologies that are not yet commercially available or cost effective, "but it is where we need to be."

The company said its plan will rely on "significant" new renewable energy resources and reducing the use of fossil fuels. MGE had previously committed to cutting 80% of carbon emissions by 2050.

More: *Wisconsin State Journal*