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FERC Extends PJM MOPR to State Subsidies

Existing RPS Resources Exempt

By Rich Heidorn Jr. and Michael Brooks

FERC voted 2-1 Thursday to extend PJM's minimum offer price rule (MOPR) to all new state-subsidized resources, saying it was needed to combat price suppression in the RTO's capacity market (*EL16-49, EL18-178*).

The long-awaited ruling, supported by Chairman Neil Chatterjee and Commissioner Bernard McNamee, both Republicans, provoked howls of protest from renewables advocates and a stinging 28-page dissent from Commissioner Richard Glick. A Democrat, Glick called the order an attack on decarbonization efforts and warned it would increase PJM capacity costs by at least $2.4 billion annually.

The ruling builds on PJM's "MOPR-Ex" proposal, filed in response to the commission's June 2018 order finding the RTO's capacity market rules unjust and unreasonable because they failed to address growing subsidies. The RTO's existing MOPR covers only new gas-fired resources. (See *FERC Orders PJM Capacity Market Revamp*.)

FERC Chairman Neil Chatterjee answers reporters' questions after the commission's meeting. | © *RTO Insider*

The order expands the MOPR to new or existing resources entitled to state subsidies. Exempted would be existing resources participating in state renewable portfolio standard (RPS) programs; existing demand response, energy

Continued on page 27

EIM Lands Xcel, 3 Other Colo. Utilities

By Rich Heidorn Jr.

CAISO's Western Energy Imbalance Market is expanding its footprint to Colorado. Xcel Energy, Black Hills Colorado Electric, Colorado Springs Utilities and Platte River Power Authority announced last week that they will join the EIM as soon as 2021.

Although the companies "have different business models, customers and geography," they said in a press release, "all share a commitment to leading the clean energy transition and believe the WEIM will provide the most benefit to their collective Colorado customers."

Three of the companies currently share resources and balance demand through a joint dispatch agreement, and the fourth, Colorado Springs Utilities, will join in March.

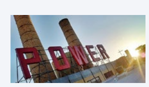
The news is further evidence of the momentum of the EIM and a disappointment for SPP, which had hoped to lure the utilities to its proposed Western Energy Imbalance Service (WEIS). The four utilities serve almost 2 million customers and reported $3.7 billion in sales in 2018.

Continued on page 9

ENERGY POLICY ROUNDTABLE IN THE PJM FOOTPRINT

About 60 people attended the Rabb Associates' Roundtable discussion on building and transportation electrification at the Philadelphia law firm of Morgan Lewis. | © *RTO Insider*

Also in this issue:



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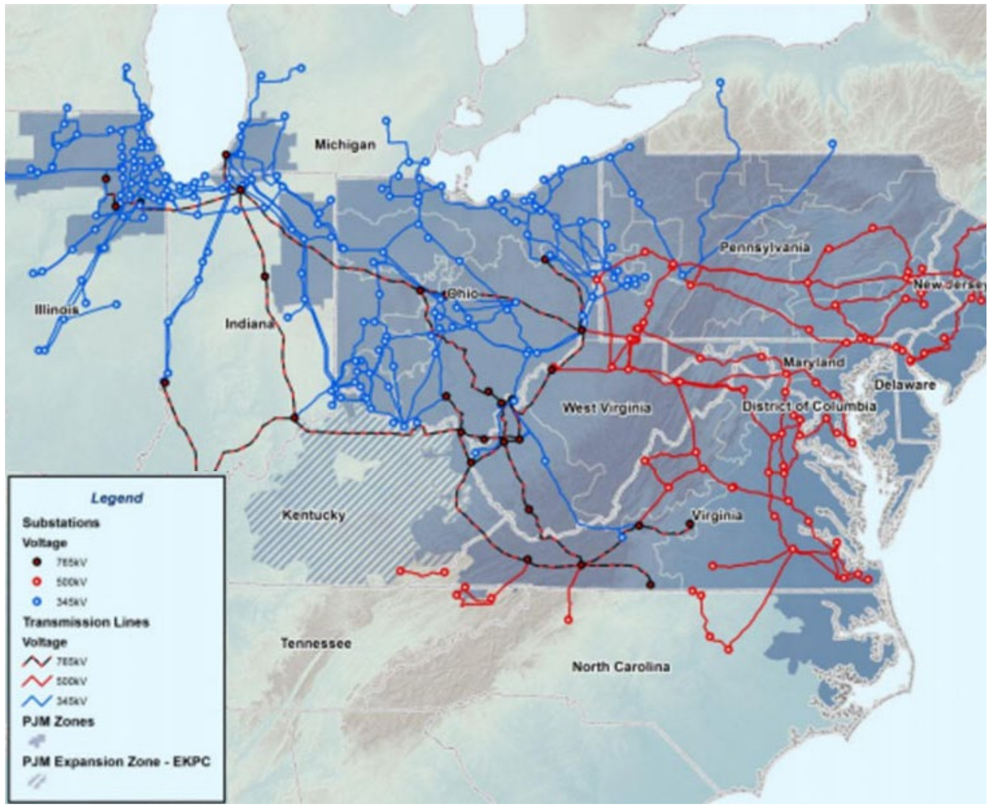
In this week's issue

FERC Rejects Rehearing in PJM Cost Allocation Saga

By Michael Brooks



PJM's high-voltage transmission | *PJM*

FERC on Thursday denied requests for rehearing and clarification of its acceptance of a settlement between PJM and its transmission owners over the cost allocation of major legacy transmission projects, the latest development in a nearly 13-year dispute that has reached the 7th U.S. Circuit Court of Appeals (*EL05-121, ER18-2102*).

In May 2018, the commission approved an agreement over how PJM would allocate the costs of transmission projects above 500 kV approved between April 19, 2007 — when FERC found the RTO's existing violation-based distribution factor (DFAX) method unjust and directed a new load-ratio share method — and Feb. 1, 2013, when FERC approved PJM's new hybrid method, combining both the DFAX and load-ratio methods. (See "Response to FERC's Cost Allocation Order," *PJM Market Implementation Committee Briefs: June 6, 2018*.)

The commission approved the settlement under the second so-called "Trailblazer approach," referring to the precedent set by a 1999 case involving Trailblazer Pipeline Co. Under the second Trailblazer approach, FERC may "approve a contested settlement as a package on the grounds that the overall result of the settlement is just and reasonable. The commission does not need to render a merits decision on whether each element of a settlement package is just and reasonable, so long as the overall package falls within a broad ambit of various rates which may be just and reasonable."

Linden VFT challenged FERC's approval under the approach, arguing that the commission needed "a detailed and independent cost-benefit analysis."

"The commission largely bases its findings on the contested settlement's general adoption of the cost allocation methodology currently contained in the PJM Tariff," Linden said in its *request* for rehearing. "The settling parties did not present, and the commission did not base its decision on, any detailed or quantitative analysis comparing costs and benefits of any of the projects."

The merchant transmission developer also said the commission's order contained "oversimplified and fallacious data analyses" and "determinations contrary to circuit court and FERC precedent."

"Any one of these flaws alone would constitute reversible error and would make the order unable to withstand an appeal," Linden warned. "That would mean that this proceeding, which officially began over 13 years ago, would continue following yet another remand without the certainty of cost allocation that the settling parties and the commission have expressed the desire to obtain."

Neptune Regional Transmission System and the Long Island Power Authority also alleged factual inaccuracies in their own requests for rehearing. Linden, along with Hudson Transmission Partners and the New York Power Authority, also requested clarification that they would not be subject to any of the current recovery charges or transmission enhancement charge adjustments provided for by the settlement.

The 7th Circuit twice remanded FERC's approval of the load-ratio share method before PJM abandoned it in favor of the hybrid method. The Illinois Commerce Commission, which had filed the original complaint with the 7th Circuit on behalf of Commonwealth Edison, was among the parties to the settlement. (See *Despite Lengthy Negotiations, PJM Cost Allocation Settlement Still Finds Detractors*.)

"We continue to find that the commission's reliance on the Order No. 1000 hybrid cost allocation method is consistent with the court's decision, and that the settlement's application of the Order No. 1000 hybrid cost allocation method achieves an overall just and reasonable result," FERC said in denying rehearing. "While the court did discuss using a cost-benefit analysis, it did not require exact quantification of costs and benefits but rather required that the benefits be 'roughly commensurate' with costs."

Regarding the requests for clarification, FERC noted that Linden, Hudson and NYPA based their argument that they should not be subject to any charges under the settlement on the fact that the commission did not approve it until May 31, 2018, when they had already converted their firm transmission withdrawal rights to non-firm transmission withdrawal rights effective Jan. 1, 2018. "In fact, Hudson and Linden sought to convert their firm transmission withdrawal rights to non-firm transmission withdrawal rights because they were subject to transmission enhancement charges," it said.

"Cost responsibility under this provision does not depend on the date on which the commission approves the settlement or the date on which the transmission owners begin collection of these charges," FERC said. "Because clarification parties held firm transmission withdrawal rights from the period from Jan. 1, 2016, to Jan. 1, 2018, we find that they are responsible for paying for the current recovery charges for that period." ■

Energy Policy Roundtable in the PJM Footprint

'Every 10th of a Degree Matters'

By Rich Heidorn Jr.

Jesse Jenkins, Princeton University, and Ryan Jones, Evolved Energy Research | © *RTO Insider*

"Every 10th of a degree matters ... every year of delay does matter and does mean increasing impacts on our climate, on our vulnerable populations, on our cities and on our economies."

—Jesse Jenkins,
Princeton University

PHILADELPHIA — Jesse Jenkins, an assistant professor at Princeton University, opened the Raab Roundtable in the PJM Footprint on Wednesday with a sobering look at the dramatic changes needed to avoid the worst impacts of climate change.

"We have to get to zero [net emissions] as rapidly as possible," Jenkins, of Princeton's Andlinger Center for Energy and the Environment, said during the roundtable on electrifying the building and transportation sectors. "How quickly we get there determines the overall amount of warming that we incur. And really, every 10th of a degree matters … every year of delay does matter and does mean increasing impacts on our climate, on our vulnerable populations, on our cities and on our economies."

Electrification and decarbonization of the generation supply are essential to meeting the net zero target by 2050, Jenkins said. "If you want to get down to zero emissions, you want to contain the overall budget, the electric sector is the most cost-effective place to start rapidly cutting emissions."

It means eliminating coal and natural gas (responsible for 60% of current electric production), unless carbon capture becomes viable, and keeping half of the existing nuclear fleet operating through mid-century.

The Pacific Northwest National Laboratory developed three scenarios for the growth in electric demand from electrification, ranging from a 50% increase by 2050 under the lowest case to 125% in the highest.

"Depending on the pace of electrification, we have to double overall electric supplies from carbon-free sources sometime in the next five to 10 years," Jenkins said. "Sometime between 2035 and 2040, we have to build the equivalent of all U.S. electric generation from new carbon-free sources to be on track. And then, if we're on a rapid electrification pace, we need to do that all again by 2050.

"We've built the entire U.S. grid we have today in about 150 years. We have to do all of that in the next 30 [years]. So, this is a huge lift. It's a tremendous transformation of our electric sources and an increasing role of electricity as a central part of our energy demand across sectors that as of today don't really rely much on electrification, like transportation and various industrial processes."

About 20 to 30 GW of new clean energy generation needs to be built per year — each 1 GW the equivalent of a large nuclear power plant.

That's four to six times faster than the peak year of U.S. wind and solar additions (5.3 GW in 2016). But Jenkins said there is some precedent: France and Sweden each added nuclear power at a pace (scaled for U.S. population growth) of more than 26 GW annually in the 1970s and '80s.

Fortunately, the cost of wind has dropped 69% since 2009 while solar and storage costs are down 88% and 85%, respectively.

But Jenkins said relying on only wind, solar and batteries would be like trying to play basketball with only point guards.

"What we need to fill out the rest of the team is something that substitutes for our natural gas- and coal-fired power plants in the firm generation that they provide today," he said referring to geothermal, biomass, biogas, nuclear, and coal or gas with carbon sequestration.

"What we need is to really be pushing these technologies forward so that over the next 10 years, we are bringing them to market in a way that's cost-effective and can complete the overall team," Jenkins said.

How Many Bites of the Apple?

Ryan Jones, co-founder of consulting firm *Evolved Energy Research*, continued the discussion with a slide illustrating how often elements of the energy infrastructure will be replaced by 2050: "the number of bites of the apple, so to speak, that we get by mid-century."

"Something like an appliance, we might have two or three replacements. For your heating system in a home, it might be one or two replacements. For a vehicle that lasts an average of 15 years, we may just get only one replacement between now and 2050."

Jenkins asked Jones how to build the electric transmission that will be needed.

"I think the federal government has to play some role," Jones said.

Energy Policy Roundtable in the PJM Footprint

"I was afraid you'd say that," Jenkins responded.

"I think the ability to site long-distance transmission involves the federal government inevitably," Jones continued. "I think what we've seen, especially in the Northeast, is … state level and regional fights about transmission: the path it takes; what state boundaries it crosses. Who benefits? And I think if we have to fight [for] each of these lines one at a time, we're never going to reach the type of transition that we're talking about."

Jones said the rates of electrification that give the best chance of reaching a zero-carbon energy system are "extremely aggressive" with 50% of new vehicle sales electric in 2030 and half of new building heating systems using heat pumps by the same year.

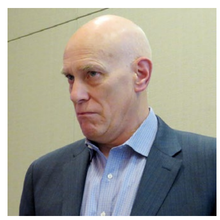
Perceptions, Slow Turnover Limit Building Electrification

Rick Nortz, Mitsubishi Electric | *© RTO Insider*

Rick Nortz, senior manager of utility and efficiency programs for Mitsubishi Electric, said heat pumps are up to the challenge but face an image problem. "Most people don't believe they work in cold temperatures," he said because earlier generations of electric heat were inefficient. The current technology is two to four times more efficient than electric baseboard heat and can produce 100% of output down to 5 degrees Fahrenheit.

Sue Coakley, Northeast Energy Efficiency Partnerships | *© RTO Insider*

Sue Coakley, executive director of Northeast Energy Efficiency Partnerships, said advanced heat pumps are cost-competitive with home gas space heating on a fuel cost basis ($/MMBTU) in PJM. In New Jersey and Michigan, which have low gas rates and comparatively high electric rates, advanced heat pumps require a higher level of efficiency (a coefficient of performance of 3.0) to compete with gas heating.



Val Jensen, Exelon | *© RTO Insider*

Building electrification "isn't a technological problem, but it is fundamentally a policy issue," said Val Jensen, senior vice president of strategy and policy for Exelon. "And we have no clear sense of how to close that gap between the technical potential for electrification of buildings and … the so-called expected case."

Buildings can last 100 years, and heating and cooling equipment are good for 15 to 20 years, limiting the opportunities for new technology, Jensen said.

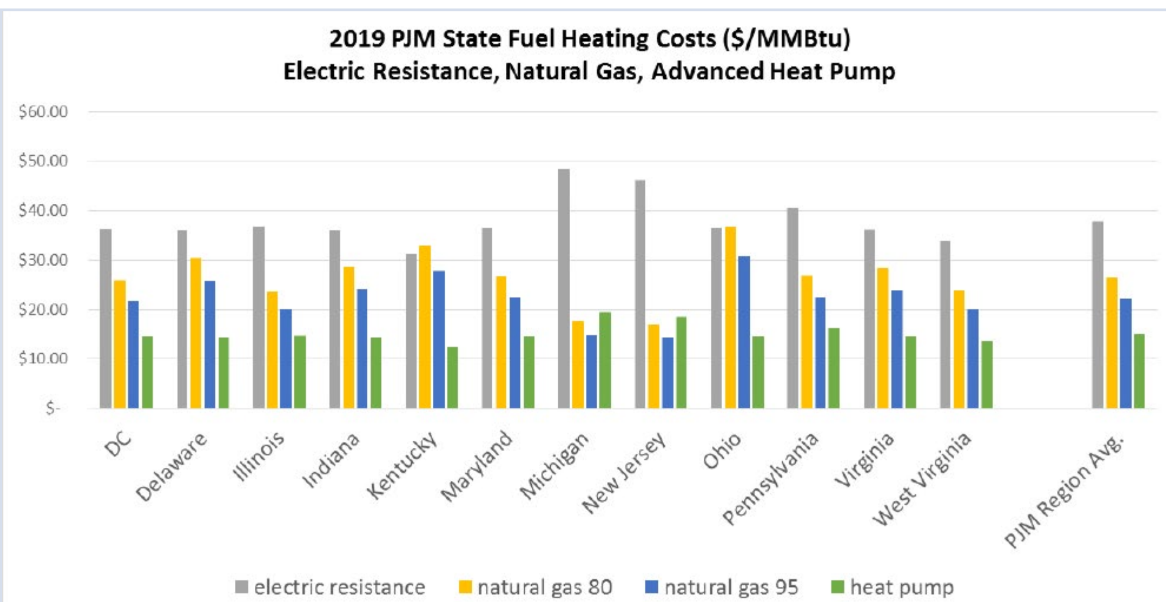
Officials in Brookline, Mass., staked out their policy position recently by banning fossil fuel furnaces in new buildings, allowing gas use only for cooking. Massachusetts could follow with a similar statewide ban, Nortz said.

Jensen said that although decarbonization is central to Exelon's long-term strategy, it and other utilities that own gas companies are facing "a deeply existential question." They must continue investing in aging gas infrastructure to ensure safety while knowing that their assets could decline in value if more jurisdictions impose restrictions on gas usage.

Jensen also noted that, under old rules that encouraged conservation, Illinois and some other jurisdictions prohibit utilities from promoting additional electric use.

The District of Columbia, which is among the cities that has pledged to become carbon-neutral goal by 2050, recently enacted a law setting "*building energy performance standards*" for existing structures larger than 50,000 square feet. The law will require those buildings to meet a median energy use intensity target that will get tougher over time. Buildings that fail will be subject to fines.

The district also is expected to introduce "net-zero ready" building codes for new construction next year, to be followed by net-zero energy codes by 2026. The difference: The first set of codes won't have an on-site renewable generation requirement but will have all the stringent energy efficiency measures. ■



Advanced heat pumps are cost-competitive with home gas space heating on a fuel cost basis ($/MMBTU) in PJM. In New Jersey and Michigan, which have low gas rates and comparatively high electric rates, advanced heat pumps require a higher level of efficiency to compete. | *NEEP*

Energy Policy Roundtable in the PJM Footprint

Dominion Sees Green in Electrification

States Team Up to Cut Transportation Emissions

By Rich Heidorn Jr.

PHILADELPHIA — Would you pay $1/month to ensure your kids ride in nonpolluting school buses — with seatbelts? Dominion Energy is betting that will be a winning proposition in Virginia.

Dominion is funding a project to bring 50 Daimler Thomas Built buses with Proterra batteries and drivetrains to the state by the end of 2020. If all goes well, it will seek state approval to add 1,000 buses by 2025 and replace all diesel buses in its service territory, which covers two-thirds of the state, by 2030. The utility *says* it would be the largest electric school bus deployment in the U.S.

Electric buses are about $200,000 more expensive than conventional diesel but have 60% lower fuel and maintenance costs and internal air quality that is six times cleaner, the utility *says*. Dominion would pay the increased cost of the buses and will own the batteries while school districts will own the buses. Dominion estimates its rate recovery for the first 1,050 buses will be about $1/month for average residential customers.

"We get batteries distributed all across Virginia. We get mobile batteries that can be taken where they need to be taken if there's an outage. We get batteries that can be sold into PJM's energy [market]. We get batteries that can be used for grid stabilization on the distribution system," explained Lisa Moerner, Dominion's director of innovation and sustainability technology.

Lisa Moerner, Dominion Energy | © *RTO Insider*

"We get the batteries; they get the buses," Moerner told Raab Associates' Energy Policy Roundtable in the PJM Footprint on Wednesday. "Students get clean air. It's a win, win, win."

This is the new Dominion — the one that has cut coal's share of its generation mix from 46% to 12% since 2007. It has an internal team working toward net zero emissions, in line with the state's goal of a 100% reduction by 2050.

Accused of dragging its feet on offshore wind a few years ago, it is now planning what it says will be the *largest OSW project* in the U.S, with 210 turbines having a combined capacity of more than 2,600 MW.

The utility is urging its employees to drive EVs, installing charging stations at some of its offices, and hopes to have one-quarter of its own light-duty fleet converted to electric power or plug-in hybrids by 2025.

Between 2017 and 2018, EV sales in Virginia *more than doubled* to 6,375, and a Navigant study projects the state will have 105,000 to 224,000 EVs by 2030 — using 334,000 MWh to more than 732,000 MWh of power annually.

"We would love this growth rate for electric vehicles," Moerner said. "EVs are a huge growth opportunity for us."

The utility has asked Virginia regulators for approval to deploy automated meter infrastructure throughout its service territory and is developing a voluntary time-varying rate and evaluating demand-side programs to encourage EV charging during off-peak hours.

The reason for the shift is simple, Moerner said.

"The driving force is to continue to be a company. If you look at where were going with climate change, with people wanting solar on their roofs and everyone wanting an EV in their garage, if we don't provide those services somebody else will."

The company sees electrification opportunities beyond school buses and passenger vehicles, saying there are applications in the construction and mining industries and in airport baggage handling.

EV maker Tesla also is looking beyond passenger vehicles with plans to begin production in 2020 on an electric semi-truck. It would re-

Patrick Bean, Tesla | © *RTO Insider*

place class 8 diesels that get as little as 6 mpg (meaning a truck that drives 150,000 miles a year will burn 25,000 gallons of diesel fuel).

The plan is to charge them overnight or at warehouses during loading and unloading. "Once these vehicles are cost-effective, fleets are going to want to electrify quickly," said Patrick Bean, Tesla's senior manager of policy and business development.

Bean also discussed Tesla's new Cybertruck, a pickup that had a *less than auspicious introduction* at a press conference in November, when its supposedly indestructible windows shattered during a press conference with founder Elon Musk. "Love it or hate it, people are talking about it," Bean said. "Pickup trucks are the best-selling passenger vehicles in the U.S. They are also among the least efficient vehicles in the U.S."

Tesla reported more than 200,000 refundable deposits for the truck, which won't be available until late 2021 at the earliest.

Bean said the company has increased the range on its vehicles by 10% this year because of efficiency gains on power trains. "Whether I work for Tesla or not, I am never buying another gas car," he said.

Transportation Climate Initiative

The roundtable, at the law firm of Morgan Lewis, came a day after the Transportation and Climate Initiative (TCI), an alliance of Northeast and Mid-Atlantic states, released its *draft memorandum of understanding* for setting a cap

Energy Policy Roundtable in the PJM Footprint

on pollution from transportation effective in 2022.

The MOU would require wholesale fuel companies to purchase pollution allowances in a model based on the Regional Greenhouse Gas Initiative's limits on power plant emissions. Assuming fuel companies pass the cost of the allowances to consumers, it would increase gasoline prices by 5 cents/gallon to 17 cents in 2022. The fees could fund EV chargers, electric buses, bike lanes and other infrastructure to reduce carbon, while the higher costs would encourage a switch to EVs or other alternatives to carbon-based fuels. The proposal is projected to cut emissions from transportation by as much as 25% by 2032.

TCI includes New York, all of New England except New Hampshire, and the Mid-Atlantic region of Delaware, Maryland, New Jersey, Virginia, D.C. and Pennsylvania.

"It's no secret to anybody in this room that Pennsylvania has long been a leader in coal, oil, natural gas [and] nuclear power," said Patrick McDonnell, secretary of the state Department of Environmental Protection. "But now Gov. [Tom] Wolf wants to be a leader in taking on the climate crisis." Wolf's January executive order calls for a 26% reduction in greenhouse gas emissions from 2005 levels by 2025 and an 80% cut by 2050, in line with the 2015 Paris Agreement on climate change, McDonnell said.


Pennsylvania DEP Secretary Patrick McDonnell | © *RTO Insider*


Erika Myers, Smart Electric Power Alliance | © *RTO Insider*

Erika Myers, a principal in transportation electrification for the ***Smart Electric Power Alliance***, said EVs could boost peak hourly electric demand by as much as 30%, making it essential that utilities engage in both passive behavioral load control and active direct load control to smooth usage. Myers said most utilities are not adequately preparing for EV loads. "Many utilities don't include EV charging in distribution planning, or the mechanisms by which they're incorporating that load are … not as sophisticated as they could be," she said. ■

CAISO/West News

CAISO's 2020 Vision Anticipates Big Change

Major Initiatives, Avoiding Shortages Among Goals

By Hudson Sangree

CAISO will have its work cut out for it next year, with more than a dozen major policy initiatives moving forward as well as efforts to head off predicted electricity shortfalls starting in summer 2021.

At Thursday's Board of Governors meeting, staff provided a *rundown* of the policies expected to occupy the ISO in the months ahead.

A major focus will be on managing operational risk from a transforming grid, one that must integrate increasing amounts of renewable electricity and battery storage, said Greg Cook, CAISO executive director of market infrastructure policy.

Meeting California's clean energy goals and expanding the Western Energy Imbalance Market from a real-time-only to a day-ahead market also occupy the 2020 agenda.

"We're going through an unprecedented amount of change," Cook told the board.

An initiative on *hybrid resources* promises to be one of the largest and most complex of the ISO's 14 policy initiatives in 2020, Cook said. Because of California's move toward carbon-free energy and the limits of solar energy to meet evening peak demand, developers have proposed 25,000 MW of projects that pair storage with existing or new generation.

Those projects won't all materialize, Cook said, but "we could easily see 2,000 to 3,000 MW coming online in the next few years," particularly to meet the impending capacity shortfalls in 2021. (See *CAISO, CPUC Warn of 'Reliability Emergency.'*)

In his *presentation* on the ISO's 2020 outlook, Mark Rothleder, vice president of market quality, focused on the prospect of shortfalls starting in 18 months and the need to get ahead of the problem. Among the challenges are dealing with increased ramping needs and prolonged weather events that diminish solar generation, he said. Currently, rapid increases in demand are met by natural gas generation and electricity imported from other Western states, he noted.

CAISO's headquarters in Folsom, Calif. | © *RTO Insider*

In one slide, Rothleder showed a three-hour ramp on Jan. 1, 2019, that started mid-afternoon and required more than 15,000 MW of additional power, most of it coming from natural gas and imports.

To put the figure in perspective, "that's like ramping 12 Diablo Canyons over a three-hour period," Rothleder said, referring to California's last operating nuclear generating station. The two-unit Diablo Canyon Power Plant, owned by Pacific Gas and Electric, is scheduled to retire starting in 2024, further exacerbating the state's need for reliable electricity supplies.

The same three-hour ramp is expected to grow to 25,000 MW by 2030, he said. By that time, solar combined with batteries should be contributing more to ramping needs. However, to make that work, improvements in dispatching solar power are required, as is increased visibility and control of commercial and residential solar generation, he said.

Shifting focus, Rothleder expressed concern about multiday weather patterns that limit solar generation. A common California winter weather pattern consists of multiple rainstorms rolling in from the Pacific Ocean, with short breaks between the storms, over the course of a week.

Rothleder cited a period from Jan. 13 to 18 when storms washed over California, reducing solar generation to 20% of expected capacity. Gas power and imports can make up the difference now, but Senate Bill 100, enacted in 2018, requires elimination of fossil fuels from the state's energy mix by 2045.

As reliance on solar power increases, and dependence on fossil fuels decreases, the state will require storage resources capable of dealing with prolonged cloud cover, he said. Batteries with a four-hour run time, the main type used today, won't do the job, he said.

A similar situation in July on the Hawaiian island of Kauai resulted in rolling blackouts, he noted.

"If we want to get off gas, we need a solution, including storage," Rothleder told the board. ■

CAISO/West News

EIM Lands Xcel, 3 Other Colo. Utilities

Continued from page 1

The companies said that a Brattle Group study concluded that the EIM had more potential to lower production costs "due to the size of its market footprint and the diverse resources available."

The companies said the EIM also offered lower administrative costs and noted its exploration of a day-ahead market, which they said will allow the integration of more renewables.

"We're very excited with their announcement," CAISO spokeswoman Vonette Fontaine said. "Utilities are recognizing the savings the EIM brings to its customers, along with their ability to integrate carbon-free resources."

SPP did not immediately respond to a request for comment.

"This decision is an important next step in our efforts to keep our customers' bills low and provide more 100% carbon-free energy like wind and solar," said Alice Jackson, president of Xcel Energy Colorado, the state's largest load-serving entity.

The companies said they will work to finalize their implementation agreement with the EIM over the next several months and have set a target of 2021 for joining the market.

The companies announced they were evaluating the EIM and WEIS in September, after the state enacted legislation requiring utilities to submit greenhouse gas-reduction plans and instructing state regulators to investigate the potential benefits of joining a regional energy market. (See *Colorado Utilities Examine Market Membership*.)

In April 2018, Xcel had pulled out of a plan for the Mountain West Transmission Group to join SPP, saying it wasn't in its best interests. (See *Xcel Leaving Mountain West; SPP Integration at Risk*.)

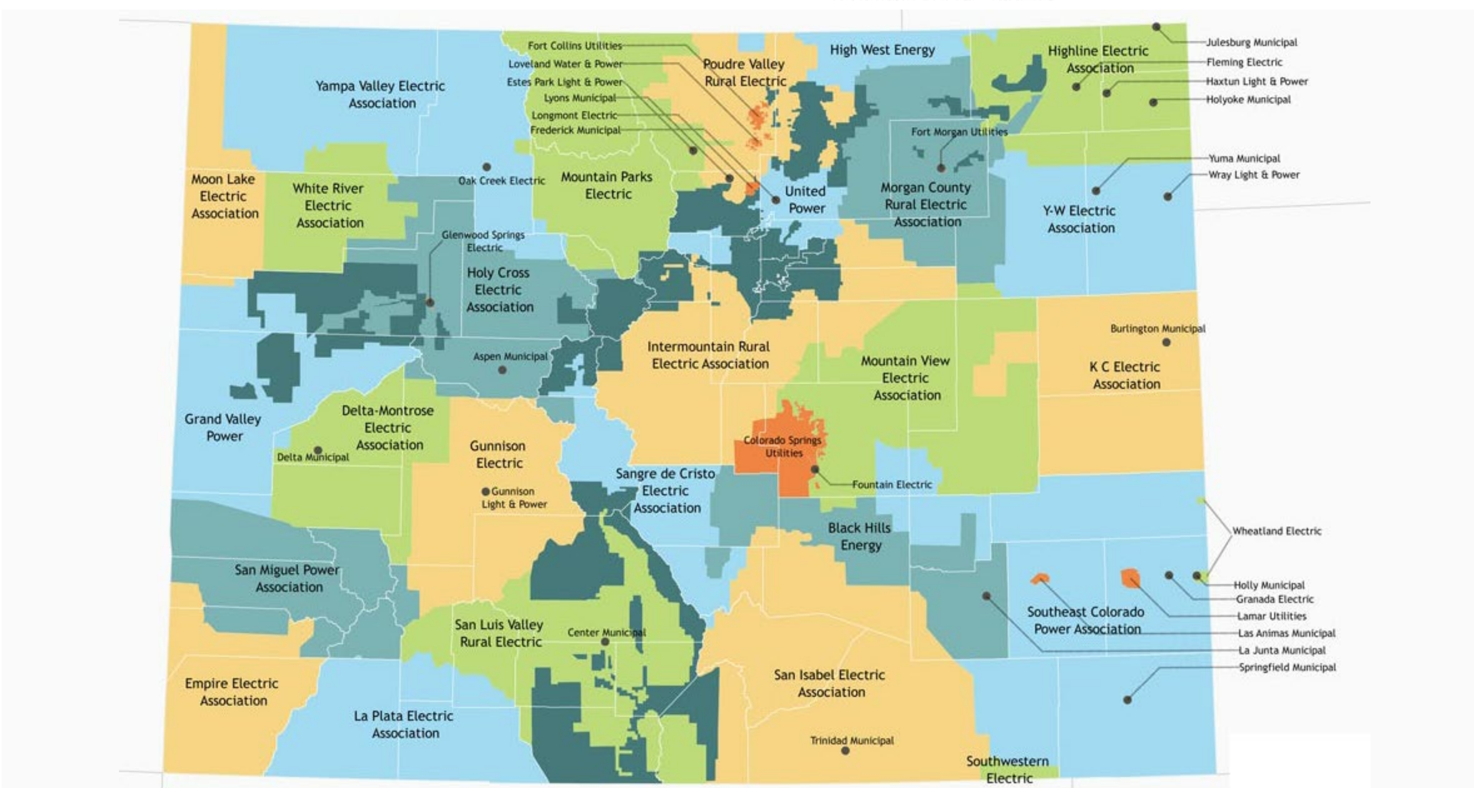
Xcel's Public Service Company of Colorado had almost 1.5 million customers and $2.7 billion in revenue in 2018, according to the Energy Information Administration.

Colorado Springs has more than 231,000 customers, with Black Hills serving almost 97,000.

Platte River Power Authority provides wholesale electric generation and transmission to the utilities of Estes Park, Fort Collins, Longmont and Loveland, which have more than 162,000 customers.

CAISO says the EIM has *saved* its nine current participants $801 million since it launched in 2014. Nine other entities will join the EIM next year, with the Los Angeles Department of Water and Power following in 2021. ■

Hudson Sangree contributed to this article.



Colorado utilities | *State of Colorado*

CAISO/West News

Judge OKs PG&E Deals with Fire Victims, Insurers

Utility also Announces Wildfire Settlement with State Regulators

By Hudson Sangree

Pacific Gas and Electric scored major wins Tuesday in its effort to emerge from Chapter 11 bankruptcy with its shareholders still in control of the utility.

Judge Dennis Montali | *Commercial Law League of America*

In U.S. Bankruptcy Court in San Francisco, Judge Dennis Montali approved PG&E's $13.5 billion settlement with wildfire victims, despite objections from Gov. Gavin Newsom and lawyers for a group of bondholders trying to seize control of the company.

The U.S. Bankruptcy Court for the Northern District of California in San Francisco | *© RTO Insider*

Montali also approved a controversial $11 billion settlement between PG&E and the subrogation claimants, a coalition of insurance companies and hedge funds that hold claims against the utility for insurance payments to businesses and homeowners.

And PG&E announced it had made a pact with the California Public Utilities Commission's Safety and Enforcement Division over its role in starting wildfires in its service territory in 2017 and 2018, agreeing to not seek reimbursement from ratepayers for more than $1.6 billion in wildfire-related costs.

"If approved, this would be the largest dollar amount ever imposed by the commission in connection with alleged wildfire-related violations," lawyers for the parties wrote in a *joint motion* to the CPUC.

Lawyers argued on Tuesday for six hours before Montali, who weighed the ramifications of the utility's deal with fire victims and the governor's harsh criticism of the restructuring support agreement between PG&E and the Tort Claimants Committee (TCC), which represents fire victims.

The judge noted that Newsom — in a court filing Monday and a letter to PG&E CEO Bill Johnson last week — had not objected to the $13.5 billion amount but had said the utility's amended bankruptcy plan failed to meet the requirements of AB 1054, a law the governor championed last summer.

Newsom told Johnson that he wanted wholesale change in PG&E's governance as well as provisions to let the state more quickly takeover the utility if needed. (See *PG&E Chapter 11 Plan Won't Do, Governor Tells Judge*.)

Cecily Dumas, a lawyer representing the TCC, told Montali she believed the company's reorganization plan could be amended to meet the requirements of AB 1054 and satisfy Newsom.

"Notwithstanding the fact that the governor is sending nastygrams to PG&E every few days, we have not lost hope that the debtor will be able to improve the plan so that it is AB 1054-compliant and can be confirmed," Dumas said.

Montali said he wouldn't overrule the decision by fire victims to back PG&E's proposal. It was the same reasoning he used to admit the bondholders' reorganization plan in early October. Fire victims initially backed the bondholder plan because it offered them $13.5 billion. When PG&E met that offer two weeks ago, the TCC switched its allegiance. (See *Judge Admits Takeover Plan as PG&E Starts Blackouts*.)

Dumas and other lawyers said they think PG&E's plan has a better chance than the bondholders' proposal to be quickly confirmed by the court and CPUC, allowing PG&E to exit bankruptcy by June 2020, as AB 1054 requires. If it can meet that deadline, the utility can participate in a $21 billion wildfire recovery fund established by the state.

Lawyers for wildfire victims also switched their stance on PG&E's $11 billion settlement with the subrogation claimants. After initially opposing the settlement, the victims withdrew their opposition when PG&E agreed to up its offer to them.

Victims weren't thrilled that their $13.5 billion settlement with PG&E will consist of cash and stock but agreed to accept it as the best deal they were likely to get from the utility. Under the agreement, a trust to pay fire victims will receive shares equal to about 20% of a reorganized PG&E.

"We see this as the most expedient path forward," Dumas told the judge. "This is by no means a perfect solution."

The agreement between PG&E and the CPUC was announced Tuesday afternoon as lawyers argued in bankruptcy court. It provides that the utility will spend $1.625 billion on transmission and distribution line inspections and repairs and other wildfire measures without seeking rate recovery.

It also requires PG&E shareholders to spend $50 million on system enhancements and community engagement.

"Today's filing sets in motion the next steps," which include review by an administrative law judge and the CPUC, the commission said in a *news release*.

PG&E declared bankruptcy in January after a series of catastrophic wildfires in 2017 and 2018 saddled it with potentially billions of dollars in liabilities. The blazes included the Camp Fire, the deadliest and most destructive in state history, which killed 86 people in and around the town of Paradise. ■

CAISO/West News

Western Order 845 Filings Need Fixes, FERC Says

Utilities Had Common Problems in Interconnection Protocols

By Hudson Sangree

Four Western utilities generally complied with FERC rules intended to make it easier for generators to connect to transmission grids but had shortcomings in several common areas, the commission found last week.

The compliance filings under Orders 845 and 845-A were submitted by Avista (*ER19-1959*), PacifiCorp (*ER19-1948*), Public Service Company of Colorado (PSCo) (*ER19-1864*) and Public Service Company of New Mexico (PNM) (*ER19-1955*).

FERC evaluated the filings against Order 845's 10 reforms meant to increase the transparency and timeliness of the generator interconnection process. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections*.)

Problems arose under reforms involving contingent facilities, provisional interconnections and new technologies.

Contingent Facilities

In Avista's filing, for example, FERC said the company had failed to identify specific requirements for contingent facilities. Contingent facilities are unbuilt interconnection facilities and network upgrades on which an interconnection request's costs, timing and study findings depend.

"Avista's proposed Tariff revisions lack the requisite transparency required by Orders No. 845 and 845-A because the proposed Tariff revisions do not detail the specific thresholds or criteria that Avista will use as part of its method to identify contingent facilities," FERC wrote. "Without this information, an interconnection customer will not understand how Avista will evaluate potential contingent facilities to determine their relationship to an individual interconnection request."

FERC directed Avista to file a further compliance filing within 60 days with the "specific thresholds or criteria it will use in its technical screens … to achieve the level of transparency required by Order No. 845."

Similar deficiencies were identified and ordered corrected by FERC in the filings by PacifiCorp, PSCo and PNM.

FERC's findings on contingent facilities echoed last month's determinations on the Order 845 filings of Portland General Electric, Tampa Electric Co. and others. (See *FERC Finds Partial Compliance on Order 845*.)

Provisional Interconnection

PacifiCorp, PSCo and PNM fell short when it came to provisional interconnection services, FERC found.

Order 845 required transmission providers to let interconnection customers request provisional interconnection service when studies show there's a level of service available to accommodate an interconnection request without new interconnection facilities or network upgrades, and when the interconnection customer wants to make use of that service while it completes facilities for its full interconnection.

PacifiCorp's proposed language stated that it would update provisional interconnection studies "as system conditions warrant."

That, FERC said, would "create too much discretion for PacifiCorp regarding the frequency for updating provisional interconnection studies."

PSCo proposed to conduct updated provisional interconnection studies "if necessary, on a quarterly basis" — a proposal FERC rejected.

"While the commission gave the transmission provider discretion to determine the frequency for updating provisional interconnection studies in Order No. 845, PSCo's proposed inclusion of the phrase 'if necessary' provides PSCo unfettered discretion to determine the frequency at which it will update provisional interconnection studies," the commission wrote.

PNM had the same issue, FERC found.

Incorporation of Advanced Technologies

In Order 845, the commission allowed an interconnection customer to incorporate some technological advancements to its interconnection request without losing its queue position. It required transmission providers to develop and include in their procedures a definition of permissible technological advancements that, by definition, do not constitute a material modification.

Avista said it would use "reasonable efforts" to assess a technological change request. FERC said that language wasn't acceptable. The company also failed to explain how it would evaluate a technological-advancement request to decide if it was a material modification and didn't establish a time frame for making an evaluation, FERC said.

"Accordingly, we direct Avista to file, within 60 days of the date of this order, a further compliance filing that cures these deficiencies or explains why these requirements are not necessary for this aspect of Avista's proposed procedure," FERC said.

PNM and PacifiCorp had similar problems with their technological-change request procedures, FERC said. ■

| EDP Renewables

ERCOT News

Parties to EPE Acquisition Reach Settlement Agreement

By Tom Kleckner

El Paso Electric and the investment funds seeking to buy the utility have reached a settlement with most of the parties with an interest in the transaction, they told Texas regulators on Wednesday.

EPE, Sun Jupiter Holdings and Infrastructure Investments Fund (IIF) US Holding 2 *said* that the agreement's "negotiated resolution" is in the public interest, will conserve the parties' and the public's resources, and eliminate controversy (*49849*).

The Public Utility Commission of Texas had set a Dec. 17 deadline to finalize a stipulated agreement but granted an extension to noon Wednesday. (See "Commission Denies Extension Request in EPE Acquisition," *Texas PUC Briefs: Dec. 13, 2019*.)

Parties to the agreement include the city of El Paso, PUC staff, the state's Office of Public Utility Counsel, and several consumer and labor groups. The El Paso City Council *approved* the agreement on Dec. 17, although it is still pondering EPE's municipalization.

The signatories agreed that the transaction will not result in a transfer of jobs outside of Texas, adversely affect customers' and employees' health and safety, or result in degraded service.

EPE's Rio Grande Plant in Sunland Park, N.M. | *El Paso Electric*

Administrative Law Judge Hunter Burkhalter *directed* the two remaining intervenors not party to the settlement — a local activist who once served on EPE's board and a group consisting mostly of local school districts — to respond by Dec. 30 as to whether they want to proceed with a scheduled Jan. 7-8 hearing on the sale. He warned that if the hearing goes forward, the PUC will rule on the stipulation, not the original application. The PUC had rescheduled the hearing from November to January in order to allow intervenors time to reach a unanimous agreement. (See *Parties Near Agreement on El Paso Electric Purchase*.)

EPE, Sun Jupiter and IIF, which is advised by J.P. Morgan, announced their proposed $4.3 billion purchase of the utility in June. The sale must be approved by the PUC, FERC and other regulators before becoming final. ■

ISO-NE News

ISO-NE Issues First Competitive Tx RFP

By Michael Kuser

ISO-NE on Friday *announced* its first competitive transmission solicitation to address reliability concerns associated with the upcoming retirement of the Mystic Generating Station in Everett, Mass.

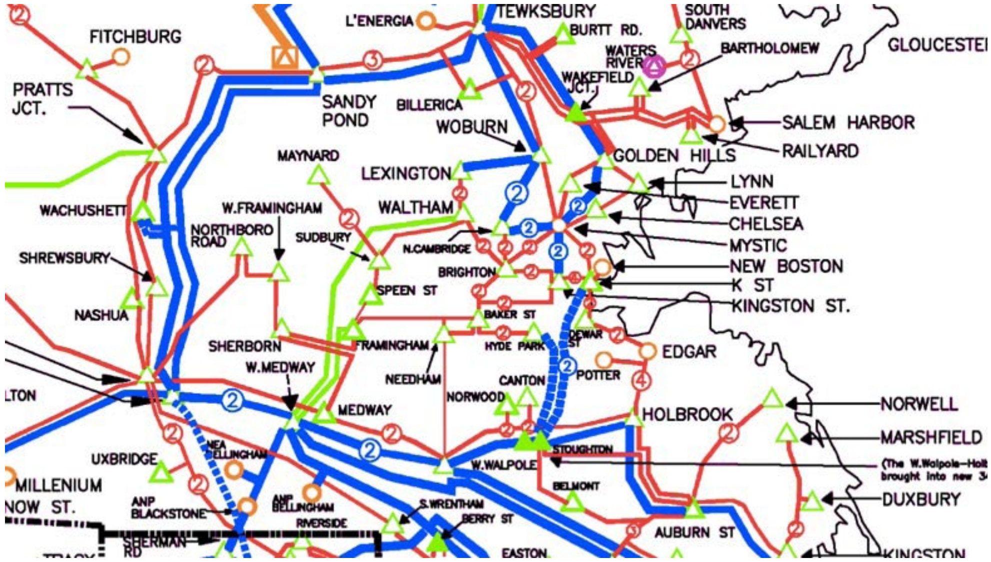
The *request for proposals* seeks to address transmission facility overloads under peak load conditions in the Boston area, as well as system restoration concerns with the underground cable system in the area.

The RTO will review all the proposals in a two-step process before selecting the preferred solution. The deadline for phase 1 proposal submissions is 11 p.m. on March 4, 2020.

ISO-NE and its Planning Advisory Committee will review the proposals to ensure they address the identified needs and are feasible and cost competitive. The RTO will then identify finalists, who will be required to provide additional details to guide its selection of the preferred solution.

FERC earlier in December approved Tariff revisions refining ISO-NE's rules for conducting competitive transmission solicitations in compliance with Order 1000, a process being tried for the first time now for solutions to non-time-sensitive needs identified in the RTO's 2028 Boston Needs Assessment Update and Needs Assessment Addendum (*ER20-92*). (See *FERC OKs ISO-NE RFP Rules*.)

Exelon announced last year that it would retire Mystic in 2022, but FERC approved a cost-of-service agreement between the company and ISO-NE to keep Units 8 and 9 operating through May 2024.



Greater Boston area electrical distribution map | *ISO-NE*

Under the competitive process, any qualified transmission project sponsor (QTPS) may submit a phase 1 proposal, while NSTAR Electric and New England Power are required to submit a joint backstop transmission solution for consideration in response to the RFP.

According to the ISO-NE 2019 Regional System Plan (RSP) *posted* on Oct. 31, "the peak load needs were found to be non-time-sensitive because the needs were present in the study horizon cases of 2028 but were not observed in the time-sensitive cases of 2022."

In addition, the system restoration need for reactive support is considered a non-time-sensitive need because the retirement date of Mystic 8 and 9 is beyond the three-year time-sensitive period, the RSP said.

The competitive solution process is detailed in Attachment K, Section 4.3 of the Tariff.

The *pro forma* agreement between the RTO and the selected QTPS spells out the development, design and construction of the project, including project milestones, status reports and cost-containment measures.

The RTO modeled its agreement on the designated entity agreement that PJM uses in its competitive transmission solicitation process. ■

Generating Units	Qualified Capacity13	Commercial Operation Year	Age (years)
Mystic 7	578	1975	39
Mystic 8	682	2003	11
Mystic 9	692	2003	11
Kendall CT	154	2002	12
Salem Harbor 5	337	2017[14]	N/A
Salem Harbor 6	337	2017[14]	N/A
TOTAL	2780		

Greater Boston area generating units over 100 MW | *ISO-NE*

ISO-NE News

ISO-NE Planning Advisory Committee Briefs

NESCOE Study Shows OSW Effects

New England's carbon emissions could decrease by an average of 1.4 million to 1.5 million short tons per 1,000 MW of offshore wind capacity added in the region, with production costs falling by $128 million to $138 million, according to a new study by the New England States Committee on Electricity, the ISO-NE Planning Advisory Committee heard last week.

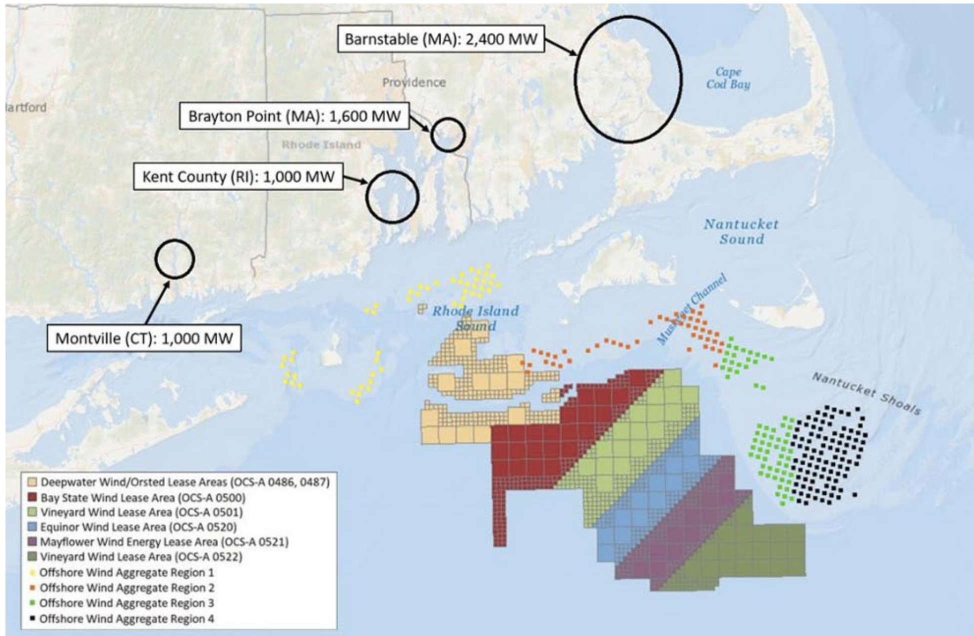
Impacts decrease as more megawatts are added, based on preliminary results from NESCOE's 2019 Economic Study outlining scenarios with as much as 6,000 MW of OSW additions. It was *presented* by Patrick Boughan, an RTO senior engineer for system planning.

NESCOE, Anbaric Development Partners and RENEW Northeast submitted requests for additional studies at the PAC meeting in April. (See *ISO-NE Planning Advisory Committee Briefs: April 25, 2019*.)

Possible additions of 8,000 MW of offshore wind will be discussed at a subsequent PAC meeting. All such additions are in the southern portion of the New England system, Boughan said.

The analysis also shows annual average LMPs decreasing as offshore wind increases.

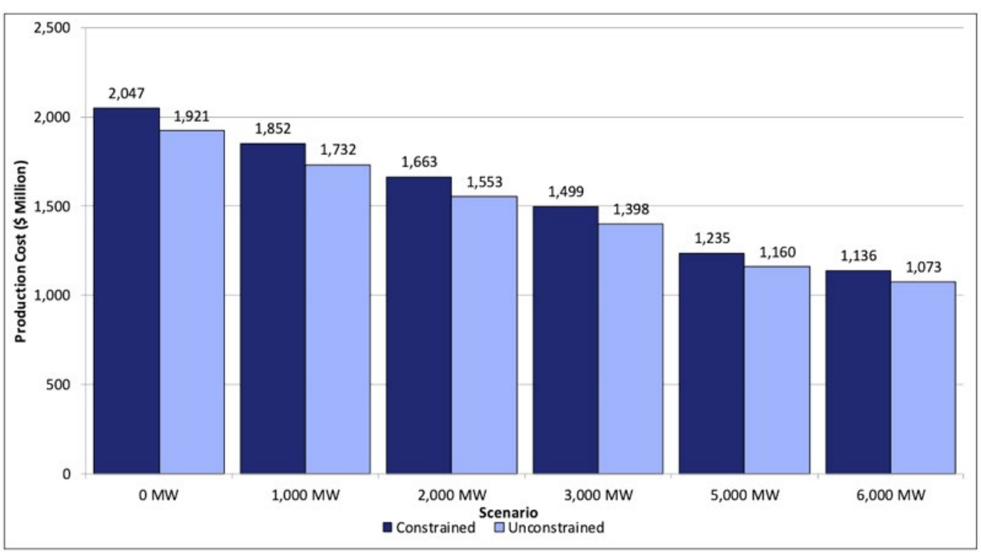
"Congestion is concentrated at the Surowiec-South interface [in Maine] and decreases as you add more offshore wind, decreasing by an average $16.5 million per 1,000 MW of offshore wind capacity," Boughan said.



Locations of NREL offshore wind sites and interconnection points used for preliminary results | *ISO-NE*

The assessment of offshore wind additions for the study do not take into consideration transmission upgrades associated with interconnection to the grid or Forward Capacity Market participation, he said.

"We're using 2006 [National Renewable Energy Laboratory] offshore wind profiles due to their availability. However, we have new 2015 offshore wind profiles in development right now, and all these results today will be rerun with 2015 profiles," Boughan said. "While we do expect those changes to affect the model, the trends we see in this presentation are expected to hold, and not vary significantly."



Production costs are lower in unconstrained cases because they utilize more zero-cost energy north of Surowiec-South.| *ISO-NE*

Improving the Regional System Plan

ISO-NE Director of Market Development Carissa Sedlacek presented a *summary* of the 2019 Regional System Plan and asked stakeholders to help improve the process for making the plan.

Following a public forum in Boston in September, the RTO's Board of Directors approved the 2019 RSP, which was *posted* on Oct. 31. (See *Overheard at ISO-NE Regional System Plan Public Forum*.)

"It takes nearly a year to develop the RSP, and we're asking you what else we can do to make it better," Sedlacek said.

The RTO last May held Grid Transformation Day as a special PAC meeting to present and discuss the technical challenges of a hybrid grid. The meeting and attendance exceeded expectations, she said. (See *'Grid Transformation Day' Highlights ISO-NE Challenges*.)

"In January, we will send out a survey to PAC members and other stakeholders to seek input on how to improve the plan, focusing on finding new ways to keep the RSP forward-looking, and on how to streamline the development process," Sedlacek said. ■

— Michael Kuser

ISO-NE News

NEPOOL Transmission Committee Briefs

Applying Tx Charges to Storage

NEPOOL's Transmission Committee last week focused on how to apply transmission charges to a storage resource when it is charging for later resale in wholesale markets and not providing a service.

The discussion came nearly a month after FERC "approved the vast majority" of the Tariff changes ISO-NE proposed in response to Order 841, according to the RTO's principal analyst for market development, Catherine McDonough, but the commission also required a further compliance filing by Jan. 22, 2020 (*ER19-470*).

In previewing the RTO's likely ***response***, McDonough said the order indicated that energy storage resources' (ESRs) behavior is similar to other load-serving entities when charging to resell at a later time, meaning transmission costs should apply.

"However, it also indicated that ESRs should not be subject to transmission charges when they're dispatched by the ISO to provide a service because the physical impacts on the bulk power system are comparable to a traditional generator's that provides the same service," she said. "The order also indicated that assessing transmission charges would create a disincentive for those resources to provide the service."

[Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article approved their remarks afterward to amplify their presentations.]

ISO-NE is anticipating both adding language to section III.1.10.6 of the Tariff to enumerate the services that will result in the transmission charge exemption and expanding its explanation regarding why exempting electric storage facilities from transmission charges is justified given the policy direction set out in Order 841, McDonough said.

The additional Tariff revisions will be discussed and voted on at the Jan. 14-15, 2020, Markets Committee meeting.

Order 1000 Reliability Exemptions

NEPOOL Counsel Eric Runge notified the committee of proceedings instituted by FERC in October into ISO-NE, PJM and SPP about their Order 1000 exemptions for reliability projects that are determined to be needed within three years to address a reliability need (*EL19-90, EL19-91, EL19-92*).

The commission contends that ISO-NE and the other grid operators appear to be thwarting Order 1000's intent to open transmission projects to competition by abusing the "immediate need" exemption for reliability projects. (See *FERC to Probe Order 1000 Competition Exemptions*.)

Each respondent must "demonstrate how it is complying with the immediate-need reliability project criteria; demonstrate that the provisions in its tariff, as implemented, containing certain exemptions to the requirements of Order No. 1000 for immediate-need reliability projects remain just and reasonable; and consider whether additional conditions or restrictions on the use of the exemption for immediate need reliability projects are necessary," Runge's ***memo*** said.

NEPOOL's Participants Committee last month filed a status ***report*** with FERC stating that some stakeholders have raised concerns about the lack of competitive transmission projects and the implementation of the three-year exemption, while others have noted the importance of implementation details to the achievement of commission policies.

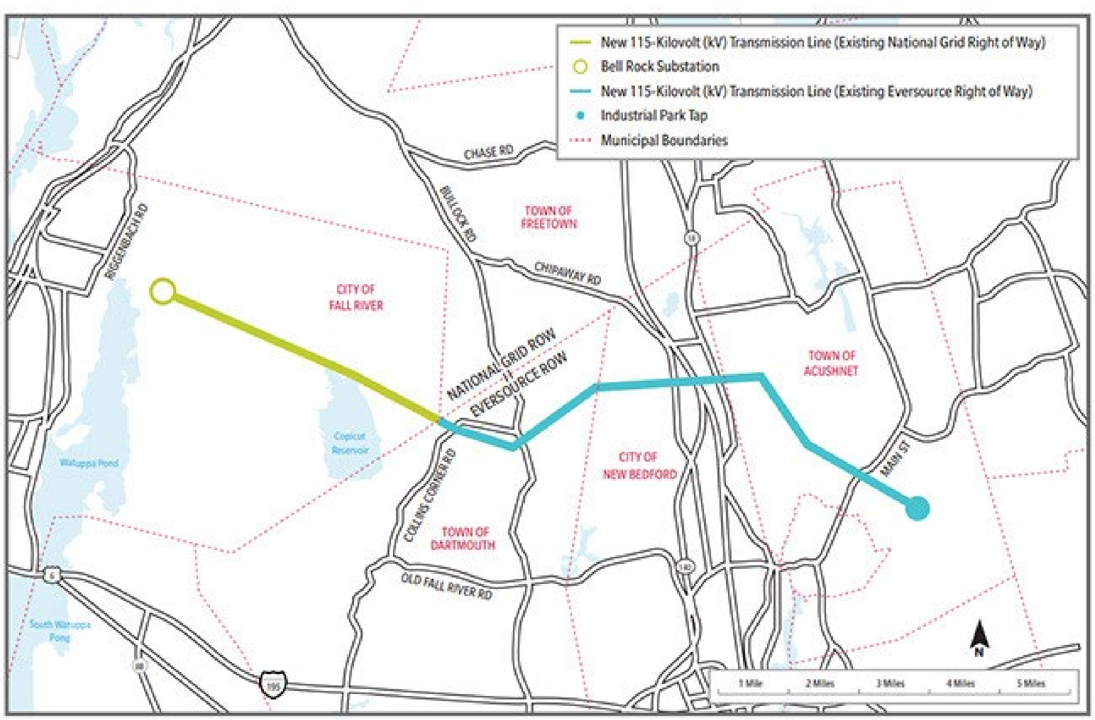
"Some participants have raised the concern that, under ISO-NE's implementation of the short-term exemption, very few reliability upgrades might be subject to competitive processes ... and some of the intended benefits of Order 1000 might not be realized," NEPOOL said, adding that the stakeholder discussions continue.

Runge also notified the Transmission Committee of FERC Opinion 569 on base return on equity methodology, including its background and a high-level summary of its key determinations.

The commission in November adopted a new methodology for calculating ROE for transmission owners and applied it to two MISO proceedings last month (*EL14-12, EL15-45*). (See *FERC Adopts ROE Methodology in MISO Complaints*.)

The Transmission Committee also confirmed Jose Rotger, of ESAI Power, as its vice chair for 2020. ■

— Michael Kuser



Eversource and National Grid have proposed a 115-kV transmission line to improve reliability in Southeastern Massachusetts and Rhode Island. It would include upgrades at Eversource's High Hill Substation in Dartmouth and Wing Lane Substation in Acushnet.| *Eversource*

Ruling Reinstates MISO TO Funding of Upgrades

FERC Decision Could Disrupt 100+ GIAs

By Amanda Durish Cook

FERC last week approved a MISO proposal to once again allow transmission owners to provide initial funding for transmission upgrades needed for generation projects, possibly upending more than 100 interconnection agreements struck over a three-year period.

The commission's decision means contracts signed between June 24, 2015, and Aug. 31, 2018, can be revised to allow TOs and affected-system operators to "unilaterally elect to provide initial funding for network upgrades, if they so choose," the commission said (*EL15-68-003, et al.*). The order applies to pro forma generator interconnection agreements, facilities construction agreements and multiparty facilities construction agreements (GIAs, FCAs and MPFCAs).

FERC's order is the culmination of four years of back-and-forth rulings between the commission and the judiciary — and is still a point of contention within the commission's ranks. Commissioner Richard Glick dissented, saying the order lacked reasoning and didn't address possible preferential treatment of TOs over interconnection customers.

MISO policy previously allowed incoming generators to self-fund new construction regardless of whether TOs wanted to fund the construction themselves. FERC in 2015 directed the RTO to remove the option for a TO to elect to fund the interconnection upgrades.

The D.C. Circuit Court of Appeals vacated FERC's decisions on the self-funding option in early 2018, saying the commission didn't consider complaints from Ameren and five other TOs who claimed the policy forced them to accept "risk-bearing additions to their network with zero return" and essentially act as "nonprofit managers" of network "appendages." The TOs had argued the Federal Power Act and Constitution prohibits FERC from forcing them to construct and operate generator-funded network upgrades. The case was remanded back to FERC.

| © RTO Insider

MISO last year said FERC's decision could affect GIAs dating back to 2015 and submitted a pre-emptive compliance filing to reflect TOs having the option to self-fund network upgrades. (See *MISO Files Revised Upgrade Funding Provisions*.)

With the commission's order, the RTO is now faced with creating a process for amending agreements and determining financial fallout.

FERC directed MISO to file Tariff edits within 60 days to reinstate the TO-funding option, "provided that such election is done in a not unduly discriminatory manner." The commission also asked for a list of all interconnection agreements over the three-year period in which the TO would like to exercise the initial funding option.

"'When the commission commits legal error, the proper remedy is one that puts the parties in the position they would have been in had the error not been made,'" FERC said, quoting a 1999 D.C. Circuit *decision* over rates on the Trans Alaska Pipeline System. "Providing transmission owners and affected-system operators the right to elect the transmission owner initial funding option for any GIA, FCA and MPFCA that became effective during the interim period is an appropriate remedy in this case to give effect to the court's vacatur, as it seeks to return the parties to the position they would be in if the commission had not issued the now vacated orders."

'Not so Burdensome'

The commission acknowledged that MISO and its members face complex issues when reopening existing agreements but said the intricacies didn't outweigh leaving the unfair treatment in place. Several MISO members, particularly those with projects in the interconnection queue, said the retroactive decision will threaten their ability to meet production tax credit deadlines if power purchase, tax equity, lender and other agreements must be revisited. The American Wind Energy Association argued that FERC's decision could cause projects in the late stages of the queue to drop out, triggering a ripple effect of restudies.

"We find that these concerns are not so

MISO News

burdensome as to overcome the presumption that the commission should place parties in the position they would have been in absent the commission's legal error. While we acknowledge that reopening existing GIAs, FCAs [and] MPFCAs may increase costs to certain interconnection customers or result in disruption to schedules … we are not persuaded that these potential impacts are so great that we should deprive transmission owners or affected-system operators of an opportunity to earn a return on the capital costs of the network upgrades built on their system that should have been expressly allowed," FERC said.

The commission also said it would not establish a process for generation developers, generation owners and interconnection customers to recover losses in light of the change. Some MISO members had asked that FERC shield developers and interconnection customers from circumstances beyond their control, but the commission said the developers and customers had been "on notice that the commission's orders on review could be remanded or vacated, and that a judicial remand and/or vacatur could require changes to agreements entered into during the pendency of these proceedings."

"As such, interconnection customers could have taken steps to mitigate these risks," FERC said.

Glick Dissents

Glick said the decision doesn't address the commission's previous concern that giving TOs the unilateral right to decide whether to fund network upgrades could be unfair to MISO's interconnection customers. He said FERC's decision may deprive interconnection customers the "opportunity to finance network upgrades with more favorable terms and rates."

And he criticized his fellow commissioners for how they chose to address the court's concerns in the order on remand.

"By simply reversing the vacated orders with nothing more than conclusory statements, the commission is now in the untenable position of neither addressing the reasons for the court's remand nor grappling with the commission's underlying concerns of undue discrimination," Glick wrote.

He said the commission should have solicited briefing after the remand to make a decision with more substantial evidence.

Instead, Glick contended, the commission sidestepped "the most significant issue presented in this proceeding: Transmission owners in MISO have the incentive to favor their own generation over others seeking to interconnect to the transmission system, and giving transmission owners the discretion to pick and choose when to self-fund network upgrades vests them with the opportunity to do so."

Glick said the commission should have granted a rehearing so it could better evaluate the risk of preferential treatment and discrimination. He also said MISO's TOs failed to prove any harms they would suffer if FERC left the three years of contracts in place, while interconnection customers will have the "economic rug [pulled] out from under" them.

"Today's order suggests that, to give effect to the court's vacatur, it must permit parties to reopen interconnection agreements previously negotiated without the transmission owners' and affected-system operators' unilateral right to elect to self-fund network upgrades. While I agree with the commission that we must, on remand, give effect to the court's vacatur, this is far from the only relevant consideration," he said. ■

MISO News

Entergy Touts $1.3B in Savings Since Joining MISO

By Amanda Durish Cook

Customers of Entergy's five utility subsidiaries have saved about $1.3 billion since they joined MISO in 2013, the company said last week.

Entergy said the savings — earned between 2014 and 2018 — can be "largely" attributed to participation in "a large pool of generating facilities that stretch across the vast MISO footprint."

"By sharing in that large pool, Entergy can maintain reliability with less power generation capacity than if it were on its own — and pass the resulting savings along to customers," the company said in a ***statement***, adding that its dispatch is also more efficient since joining the RTO.

Entergy broke down the five-year savings by subsidiary. Unsurprisingly, Entergy Louisiana — the largest division serving about 1.08 million customers — realized the greatest share at $561 million. Savings at the other utilities generally followed in order of customer base:

- $223 million for Entergy Arkansas' 711,000 customers;
- $207 million for Entergy Mississippi's 450,000 customers;
- $198 million for Entergy Texas' 454,000 customers; and
- $118 million for Entergy New Orleans' 202,000 customers.

"When we proposed joining MISO, we told our customers this would be a good business decision that would benefit them each month. We believe we have made good on that promise," said Rod West, Entergy's group president of utility operations. "Our membership in MISO has been a highly effective tool in helping our customers keep more of their hard-earned money in their pockets. It has also helped us control costs and keep our rates among the lowest in the nation. Since joining MISO five years ago, Entergy customers have saved an average of $261 million per year. These are real savings for our customers."

Entergy integrated into MISO at the end of 2013 after coming under pressure from ***state regulators*** and a U.S. Department of Justice antitrust investigation examining the company's "exclusionary conduct" in its service area. The department ***said*** Entergy would "resolve" the Antitrust Division's concerns if it followed through on promises to join an RTO and divest its transmission system to ITC Holdings. The actions would eliminate "Entergy's ability to maintain barriers to wholesale power markets," DOJ said at the time.

Three years prior to DOJ's integration, a FERC-commissioned ***study*** estimated that if Entergy's operating companies and Cleco Power joined SPP, they could stand to save a net $1.3 billion from 2013 to 2022.

Entergy last week also noted that its residential rates are about 27% below the national average, according to 2018 data from the U.S. Energy Information Administration.

MISO Chief Customer Officer Todd Hillman said he was pleased that Entergy and other members are "realizing the benefits of MISO membership."

"Our vision to be the most reliable, value-creating RTO remains strong as we help our members pass on savings to their customers. MISO's Value Proposition affirms our core belief that a collective, regionwide approach to grid planning and management delivers the greatest benefits," Hillman said in a statement emailed to RTO Insider.

MISO has scheduled a Feb. 14 stakeholder presentation to discuss its 2019 ***Value Proposition***, where it documents the savings it provides to all members. The RTO estimated it provided members between $3.2 billion and $3.9 billion in regional benefits in 2018. It doesn't estimate savings to individual members. ■

Entergy Louisiana crews work in November on new lines and a substation near the Jefferson and Plaquemines Parishes. The $100 million reliability project is slated for completion in mid-2020. | *Entergy Louisiana*

MISO Group to Probe LMR Saturation

By Amanda Durish Cook

MISO's Reliability Subcommittee meets. | © *RTO Insider*

CARMEL, Ind. — MISO's Reliability Subcommittee will next year examine whether the RTO's footprint is suffering from an excess of load-modifying resources.

Speaking during a conference call Dec. 12, Chair Bill SeDoris — who will again serve in that role in 2020 — said the subcommittee will begin discussions on the issue at its Jan. 30 meeting.

MISO stakeholders are increasingly wondering at what point LMR saturation will cause reliability concerns, with some contending the RTO may need to limit the number of emergency-only resources eligible for compensation.

SeDoris has suggested MISO undertake a study similar to its renewable penetration study, in which the RTO would seek to measure at what point an influx of LMRs would disrupt the system.

RSC Liaison Mike McMullen said MISO is currently working on a more general analysis of LMR effectiveness, with results to be presented at the Resource Adequacy Subcommittee's Jan. 8 meeting. He said it might be helpful for RSC members to listen in even though the study won't focus on LMR saturation.

"Understand, it's not the same conversation that will happen at the RSC," he told stakeholders.

Eligible End-User Customers sector representative Kevin Murray said he was surprised the stakeholder community was concerned about a surplus of LMRs.

"Physically, you balance the system by shedding load. LMRs volunteer to be first in line to shed load. If you run out of load-modifying resources, you shed firm load," Murray said during MISO Board Week earlier this month.

"We have to have some steel in the ground to generate electricity to have load to shed in the first place," SeDoris responded.

MISO is attempting to both define a possible limit on LMRs and make its procedures clearer for market participants who have criticized the communication during emergency events as being confusing. (See ***Stakeholders: MISO System Fix Too Late for Summer***.) The RTO will also deliver a presentation on LMR communication and documentation in the MISO Communication System at the Jan. 30 RSC meeting.

LMRs are not capacity resources but are considered planning resources during emergencies, able to help meet the planning reserve margin requirement for auction clearing prices. They must respond five times per year, which includes a generator verification test and four acknowledgements of MISO's scheduling instructions. A market participant can choose to forgo the test but risks being levied three times an LMP-based penalty for nonperformance during an emergency event. MISO must first declare an emergency before accessing LMR capabilities.

MISO allows resources to register as both LMR and emergency demand response, a point of confusion for some stakeholders. Emergency DR is an informal resource category created by MISO to allow demand resources to help the system during emergencies without a more involved registration process.

Stakeholders have also raised the idea of MISO not including LMRs in its planning resource margin calculation. Some have also asked the RTO to evaluate the capacity payments LMRs receive relative to their effectiveness during emergencies.

"Maybe LMRs aren't pulling their weight," MISO planning adviser Davey Lopez said during the RASC's Dec. 3 meeting.

The Upper Limits?

MISO held an informational ***workshop*** in October dedicated to the operation of LMRs. There, MISO adviser Michael Robinson said the RTO has yet to discern how many LMRs should be considered too much in the resource mix. He brought up mathematician and father of linear programming George Dantzig's ***diet problem***, where he sought to create an optimal diet from an algorithm but ended with suggestions such as 500 gallons of vinegar, 200 bullion cubes and 2 pounds of bran as meal choices. The suggestion led Dantzig to introduce upper bounds in linear programming.

"So we may have that problem with LMRs. Right now, we have 10,000, 11,000 MW. The question is … is there an upper limit?" Robinson said.

LMRs' contribution is by nature difficult to calculate, he said. "How do you prove consumption that does not occur? ... We're trying to prove the counterfactual consumption level." ■

MISO Almost There on Order 845

By Amanda Durish Cook

| MISO

MISO still has a handful of details to address before fully complying with FERC Order 845, the commission ruled last week.

FERC on Thursday directed the RTO to submit another compliance filing within 60 days to clear up its study process related to technological advancements, partial service requests and contingent facilities (*ER19-1823-001, ER19-1960*).

The commission issued Orders *845* and *845-A* in 2018 and 2019, respectively, to increase the transparency and speed of generator interconnection processes. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections*.)

The commission found that MISO only partially complied with its directive that a customer be able to request interconnection service below its full generating facility capacity. It said the RTO omitted mandatory Tariff language showing that while interconnection service will be studied at the requested level, a project could be "subject to other studies at the full generating facility capacity to ensure safety and reliability of the system, with the study costs borne by the interconnection customer."

FERC also directed MISO to explain why it gave itself 60 days to decide whether to conduct additional studies when an interconnection customer seeks to include technological advancements in its project prior to an interconnection facilities study agreement. The commission had previously prescribed 30 days to settle on any new studies and told MISO to either justify the two months or halve the timeline.

"While we understand that MISO has a large number of projects in its queue and a wide variation in studies that may be needed, we find that MISO has not justified its proposal to allow it 60 days from the date of receipt of additional information from an interconnection customer or merchant HVDC connection customer to conduct further studies," the commission said.

Finally, MISO must include a fuller description of how it determines which projects in its annual Transmission Expansion Plan are "contingent facilities." Order 845 defines those facilities as a generation project's unbuilt interconnection facilities and network upgrades that, if delayed or canceled, "could cause a need for restudies of the interconnection request or a reassessment of the interconnection facilities and/or network upgrades and/or costs and timing."

Surplus Interconnection Proposal Just Fine

FERC found that MISO easily complied with a directive that RTOs establish an expedited queue process allowing interconnection customers to use or transfer surplus interconnection service at existing facilities.

MISO submitted a partial compliance filing in May to address the surplus interconnection directive. It proposed 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*.) ■

FERC Partially Accepts NYISO Storage Compliance

By Michael Kuser

FERC last week partially accepted NYISO's plan to comply with a mandate that RTOs and ISOs develop rules to provide energy storage resources (ESRs) full access to their wholesale markets.

Order 841, issued last year, requires that grid operators recognize the unique physical and operational characteristics of ESRs in designing market participation rules.

NYISO proposed a model that allows ESRs to either blend into a higher aggregation with other storage resources and demand response, or to come together as one, virtual, larger resource. (See *Overheard at GTM's Energy Storage Summit 2019*.)

The commission on Thursday found that "NYISO has demonstrated that all [ESRs], including those located on the distribution system or behind the meter, will be eligible to provide all capacity, energy and ancillary services that they are technically capable of providing" (*ER19-467*).

However, the order also faulted NYISO's filing for a lack of details on its "metering methodology and accounting practices for [ESRs] located behind a customer meter," directing the ISO to alter its Tariff to include a basic description of such.

FERC noted its earlier determination that defers further action on the Order 841 compliance directive to allow participation in wholesale and retail markets until the commission takes action on the merits of NYISO's November responses about ESR energy bids in the day-ahead markets, and its definition of "an obligation outside the ISO-administered markets" (*ER19-2276*).

The commission did, however, agree with the Energy Storage Association that it is not reasonable to allow NYISO to adopt an open-ended effective date of no earlier than May 1, 2020, saying the proposal "inappropriately creates uncertainty for existing and prospective market participants," and ordered an effective date of no later than that date.

Separate Concurrence

In a separate concurrence, Commissioner Bernard McNamee reiterated a point he's made in other storage-related orders, saying FERC "should have, at the very least, provided states the opportunity to opt-out of the participation model created by the storage orders."

McNamee, not a member of the commission at the time Order 841 was issued, said he concurred in part and dissented in part with Order 841-A, which — among other things — affirmed that states cannot prevent ESRs from participating in wholesale markets.

"To the extent the commission's storage orders exercised authority over the distribution system and behind-the-meter ... the majority has exceeded the commission's jurisdictional authority by depriving the states of the ability to determine whether distribution-level ESRs may use distribution facilities so as to access the wholesale markets," he said. ■

		Pumped Storage	CAES	Batteries	Flow Batteries	Flywheels	Fuel Cells	Supercapacitors	V2G	ESR Aggregations
	Energy – DA	✓	✓	✓	✓		✓		✓	✓
	Energy – RT	✓	✓	✓	✓		✓		✓	✓
	Capacity	✓	✓	✓	✓		✓			
Ancillary Services	Voltage Support	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Regulation	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Operating Reserves	✓	✓	✓	✓		✓		✓	✓

Storage resources' potential services | *NYISO*

NYISO News

FERC Rejects Rehearing over PJM-NYISO Proxy Bus

By Robert Mullin

FERC on Thursday rejected a request to rehear its October 2017 *ruling* approving changes to the PJM-NYISO joint operating agreement reflecting a new operational plan for the ABC and JK interfaces between New York and New Jersey (*ER17-905*).

PJM and NYISO developed the JOA interchange scheduling and market-to-market (M2M) coordination provisions after Public Service Enterprise Group and Consolidated Edison terminated a wheeling arrangement that facilitated the flow of energy between congested areas in southeastern New York and northern New Jersey.

The revisions combined NYISO's ABC and JK interfaces with the 5018 line and PJM's western ties, creating an aggregate PJM-NY AC proxy bus. The grid operators said the changes would make use of existing interchange scheduling constructs and support the phase angle regulators on the interfaces. Pricing on the proxy bus was expected to reflect the impacts of imports and exports on the NYISO and PJM transmission systems, weighted by power flow distribution percentages. (See *Rejecting PJM 'Wheel'-related Requests, FERC Sets Inquiry*.)

In approving the changes, the commission rejected a complaint by PSEG that the changes infringed on the rights of transmission owners and there was no reliability need for the 400 MW of operational base flow (OBF) provided by the arrangement. FERC instead said it recognized the OBF was necessary to address reliability concerns in northern New Jersey and to avoid additional power from being forced over the western ties and increasing flows over already congested transmission facilities.

In its Thursday decision, FERC denied a rehearing request by PSEG and the New Jersey Board of Public Utilities, saying the complainants were incorrect in their contention that the commission erred in approving JOA revisions that failed to allocate PJM Regional Transmission Expansion Plan costs to New York beneficiaries of the OBF arrangement.

FERC noted that PSEG concedes that the JOA "is an operational protocol and that it does not appear to meet the definition of firm point-to-point transmission service, transmission service or similar terms under the PJM or NYISO Tariffs." Instead, the commission, said, the OBF is an operational protocol "that expressly does not provide firm transmission service and does not allocate costs to an entity like Con Ed."

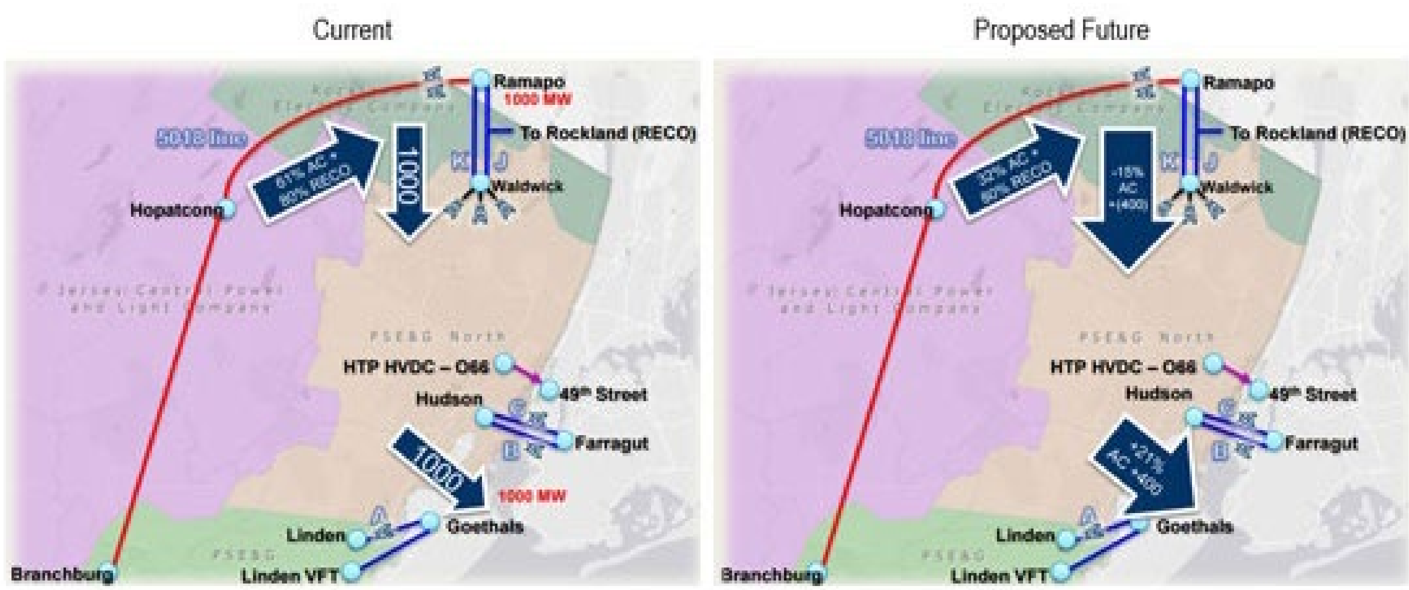
"This materially distinguishes the JOA from the now-terminated [wheeling transmission service agreements] to which Con Ed was a party and under which Con Ed was allocated costs due to its firm transmission service on both the NYISO and PJM systems," the commission wrote.

FERC also disagreed with PSEG's contention that the commission was wrong to rely on PJM and NYISO analysis showing the OBF was needed to maintain reliability. PSEG had argued the analysis was flawed because it combined an assumption of congestion during summer peak conditions with a level of interchange — 2,500 MW — that would never occur during the summer.

"PSEG does not address NYISO's and PJM's explanation that there were hours between 2014 and 2016 during which the net interchange between PJM and NYISO exceeded 2,500 MW. It was therefore reasonable for the commission to rely on PJM's studies for demonstrating actual historical flows and a reasonable net interchange value," FERC said.

The commission also said it found "unpersuasive" PSEG's assertion that NYISO and PJM should rely on existing NERC transmission loading relief procedures instead of the OBF.

"As the commission explained in the October 2017 order, the NERC procedures are a less economically efficient outcome compared to the RTOs' proposal to implement economic interchange over the ABC interface and JK interface and also utilize M2M PAR coordination at these interfaces," FERC said. "PSEG does not disagree that transmission loading relief procedures are out-of-market mechanisms, and that in PJM they are specifically emergency in nature and in NYISO are used when necessary for maintaining reliability in NYISO." ■



The PJM-NY AC proxy bus is intended to guarantee 400 MW of operational base flow between southeastern New York and northern New Jersey. | *PJM*

NYISO News

FERC Denies IPPNY Complaint over Capacity Imports

FERC on Thursday denied a complaint by the Independent Power Producers of New York seeking to bar NYISO from allowing PJM resources to sell installed capacity into the ISO's Zone J using unforced capacity deliverability rights facilities (*EL18-189*).

The ruling ended a year and a half of back-and-forth filings among IPPNY and intervenors. IPPNY contested the rights of several PJM-controlled merchant transmission facilities (MTFs) in New Jersey to export power to Manhattan and Staten Island, alleging that New York's use of PJM capacity withdrawals threatened system reliability.

NYISO argued that IPPNY incorrectly assumed that transactions across Zone J MTFs would be subject to curtailment on the same basis as non-firm service within PJM. (See *NYISO Business Issues Committee Briefs: Sept. 12, 2018*.)

The commission concluded that NYISO's Tariff does not require that MTFs, as external capacity suppliers, have firm transmission withdrawal rights in the external control area to qualify to supply capacity to NYISO.

Con Edison's Goethals Substation on Staten Island | *Con Edison*

"Rather, the Services Tariff requires only that the external capacity supplier show to NYISO's 'satisfaction' that its capacity is deliverable to NYISO and 'will not be recalled or curtailed,'" the commission said. ■

— Michael Kuser

NYISO ESCO Ruling Was Right, FERC Says

By Hudson Sangree

FERC said Thursday it won't reconsider NYISO's decision to deny membership to the successor to a bankrupt energy service company (ESCO) (*EL19-39-001*).

Light Power & Gas of NY (LPGNY) had sought rehearing of FERC's June order upholding NYISO's decision to exclude it from joining until its bankrupt predecessor, North Energy Power, paid its outstanding debts to the ISO. (See *FERC Upholds NYISO Treatment of ESCO as Successor*.)

A screenshot of the bankrupt North Energy Power's website | *North Energy Power*

NYISO expelled North Energy in October after the company filed for bankruptcy and its unpaid obligations exceeded its collateral.

LPGNY filed its application to join NYISO one week after North Energy's membership was terminated. The two companies had the same principal personnel and had served or sought to serve the same customers in the same service territory, FERC noted.

In a conversation with a NYISO manager, one of the principals had "expressed a desire to get his customers back," FERC said.

LPGNY argued NYISO had found incorrectly that it was North Energy's successor and liable for its debts.

FERC disagreed. The commission looked to its own precedents after finding NYISO's transmission tariff was "silent with respect to the question of whether two different limited liability companies with close ties can be treated as the same transmission customer," it said.

"The commission found that the close overlap of LPGNY and North Energy presented circumstances in which NYISO's treatment of LPGNY and North Energy as one transmission customer was reasonable," FERC wrote.

In its rehearing request, LPGNY argued that the "starting point for tariff interpretation is determining whether the relevant tariff language is ambiguous, and that the commission never made a finding of ambiguity," FERC said. "LPGNY contends that under [two prior FERC decisions] … the commission must declare tariff language ambiguous prior to relying on extrinsic evidence."

FERC decided, however, that the silence of the NYISO tariff on whether closely related companies can be treated as the same transmission customer "is adequate to permit the commission to rely, as it did in the complaint order, on commission precedent and extrinsic evidence, in discerning the meaning" of the relevant section of NYISO tariff. ■

NYISO Management Committee Briefs

Short-term Reliability Process

NYISO's Management Committee on Wednesday recommended that the Board of Directors approve creating a short-term reliability process (STRP) to evaluate and address reliability impacts.

Keith Burrell, the ISO's manager of transmission studies, *presented* the proposal and said the STRP may result from both generator deactivation and transmission facility reliability needs identified in a quarterly short-term assessment of reliability (STAR) study.

The new setup would enable NYISO to respond to changes on the system in a timely fashion while providing a better structure than the ad hoc generator deactivation process to address observed needs, and improve workload management for the ISO and responsible transmission owners, according to Burrell.

Revisions would be applied to Tariff sections *23.4.5.6* and *30.4*, which were posted on the ISO's website on Dec. 17 at the request of the Independent Power Producers of New York.

Related Tariff changes would expand the generator deactivation rules to apply to non-market participants that possess the authority to decide whether or when to deactivate a generator. To address non-market participants, the revisions include changes to the generator registration documents and the creation of a new responsible generator party certification.

The proposed revisions include a de minimis threshold of 1 MW to excuse generators with a lower nameplate rating from the obligation to comply with the generator deactivation rules in the STRP before they are permitted to deactivate.

The ISO anticipates February 2020 board approval and would file revisions with FERC requesting a May 1, 2020, effective date. With FERC acceptance, the first STAR would commence July 15, 2020.

The 2020 Reliability Needs Assessment would incorporate the effects of the Tariff changes.

NYISO Strategic Plan 2020-2024

Executive Vice President Emilie Nelson *presented* NYISO's Strategic Plan for 2020-2024, saying that stakeholders want the ISO to continue to be an authoritative source of information for policymakers.

"We heard that we need to focus on our planning processes and that the class year work needs to be streamlined," Nelson said. "Passage of the Climate Leadership and Community Protection Act further emphasized the need to continue to think through strategic priorities for the next five, 10 and even 20 years."

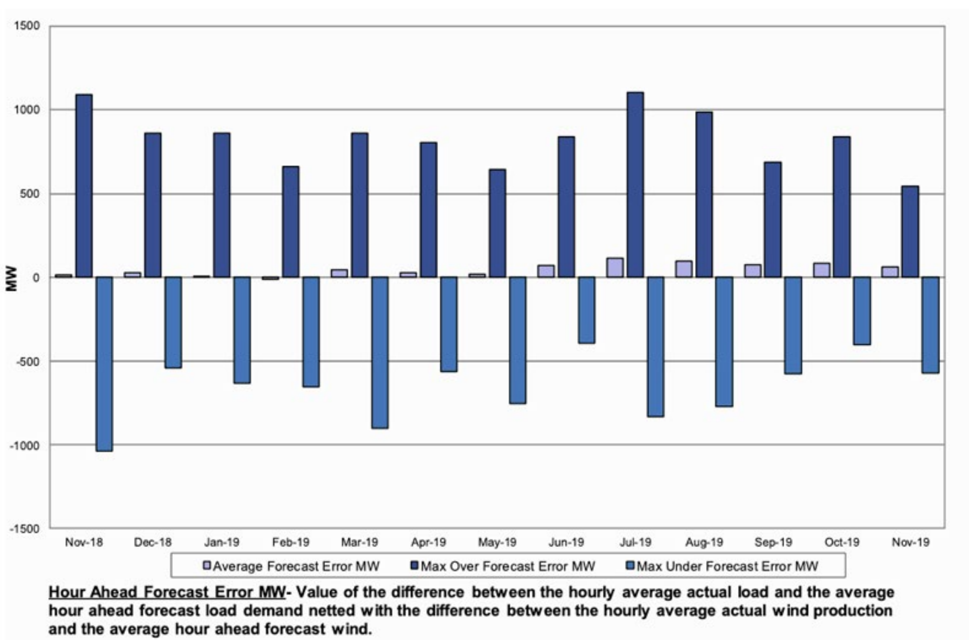
The new law (*A8429*) requires 70% of the state's electricity to come from renewable sources by 2030 and for power generators to be zero-emitting by 2040. It also raises the installed solar target to 6 GW by 2025 and calls for the state to procure 9 GW of offshore wind by 2035.

"If you look at how much renewable and distributed energy resources are going to need to come online to achieve the goals, the pace of change will be faster than anything we've ever seen."

—NYISO CEO Rich Dewey

CEO Rich Dewey said the board concluded that "we're working on all the right stuff but wanted us to think about the pace of change."

"Given CLCPA, there's going to be tremendous pressure on the schedule, and we need to move more deliberately and quicker than we have in the past," Dewey said. "If you look at how much renewable and distributed energy resources are going to need to come online to achieve the goals, the pace of change will be faster than anything we've ever seen."



To enhance reliability performance metrics, NYISO has begun to measure daily and monthly net load forecast performance against 30-minute and hour-ahead forecast error. | *NYISO*

EMS Update, New Reliability Metrics

Dewey said NYISO is working to deploy by Feb. 1 a new energy management system and business management system, both delayed in October because of problems related to stability and synchronization of data. (See "New System Software by March," *NYISO Management Committee Briefs: Nov. 20, 2019*.)

"We moved into our parallel test window today and are running two systems side by side," Dewey said. "We want to be ready for deployment as early as possible in 2020, as early as Feb. 1, if the weather permits."

COO Rick Gonzales highlighted the use of new graphs in the monthly operations *report* to reflect enhanced reliability metrics, with the ISO now measuring daily and monthly net load forecast performance against 30-minute and hour-ahead forecast error. ■

— Michael Kuser

PJM News

FERC Releases Documents in PJM Fuel-cost Dispute

By Christen Smith

FERC last week released the disputed fuel-cost policy (FCP) at the center of a redacted complaint that PJM's Independent Market Monitor filed last year against the RTO for not assessing a penalty against a generator (*EL19-27*).

The commission posted a mostly unredacted *version* of Tenaska Power Services' response to the Monitor's complaint, including the FCP in use Jan. 5-6, 2018, when the alleged violations occurred at the dual-fuel Brandywine Power Facility in Prince George's County, Md.

The Monitor protested the release after FERC's *notice* last month proposing to sunshine the docket, arguing that the confidential filings contain information that would undermine the markets and potentially give other participants insight into how Tenaska structures its energy offers.

FERC was unconvinced by that argument.

"While the fuel-cost policy details how the market seller develops its fuel cost, the fuel-cost policy lacks specific information that would be necessary for other competitors to estimate its actual energy offer," FERC said Dec. 12 in its order approving the release. "The majority of the relevant cost data at issue here is not competitively sensitive information, but information available from a publicly available source. Moreover, these data are no longer current, as the data relate to a specific event that occurred nearly two years ago on Jan. 6, 2018."

Tenaska Defends Actions

Tenaska's unredacted response — originally filed in January — shows the company insisting it didn't violate its FCP when it used third-party quotes for natural gas prices after no applicable trades became available on the Intercontinental Exchange in time to calculate day-ahead market offers.

The Monitor interpreted the language of Brandywine's FCP to prohibit Tenaska from making offers in such an event — a choice that would leave the capacity resource facility subject to nonperformance penalties should extreme weather conditions disrupt its fuel oil supply, Tenaska said.

"In short, there is no reasonable basis for limiting PJM's dispatching options, or for putting generators in a position where they are potentially subject to severe penalties or are unable to recover their costs, simply because the Market Monitor is taking an overly restrictive view of a PJM-approved FCP," Tenaska said.

Houston-based KMC Thermo owns Brandywine and maintains a contract with Tenaska that allows the company to sell energy and ancillary services in PJM's markets. KMC authored the disputed FCP using a standardized template available on Monitoring Analytics' website, approved by PJM and subsequently reviewed by the Monitor before implementation, Tenaska said.

In defense of its actions, the company pointed to a statement from the FCP that says, "under a set of defined market conditions, natural gas costs may be based on independent third-party quotes."

"At the end of the day, the broad language in the FCP permitting the use of third-party quotes was provided to both the Market Monitor and PJM and, absent any objections by the Market Monitor, was properly accepted by PJM," Tenaska said. "Regardless of the Market Monitor's hindsight dissatisfaction, there is no basis for claiming that the FCP must now be read in such a manner that it 'does not allow the use of offers from ICE or estimates from an affiliate company or from an independent third party.'"

The Brandywine Power Facility in Prince George's County, Md. | *Brandywine Power*

Market Power Precedent

The Monitor, in its initial complaint against Tenaska filed in December 2018, said the case "presents an important precedent for the role of fuel-cost policies in protecting the PJM energy market from market power abuse."

"If PJM accepts market sellers' unreasonable after-the-fact arguments to justify developing fuel costs using a method not defined in the fuel-cost policy, fuel-cost policies become meaningless and fail to serve the functions that the commission identified," the Monitor said.

The Monitor first alerted Tenaska and PJM to the alleged violation in February 2018. Tenaska defended its actions to PJM the following April, with the RTO notifying the Monitor four months later that it would not penalize the company.

PJM asked FERC to dismiss the complaint in January 2019 on the grounds that the Monitor lacked the authority to override the RTO's interpretation of Tenaska's FCP. Ultimately, in a separate docket, FERC reaffirmed the Monitor's right to protest FCPs. (See *FERC Upholds Monitor's Right to Protest Fuel-cost Policies* and *Another Win for PJM Monitor on Fuel-cost Policies*.)

Collusion Concern

The Monitor reiterated its confidentiality concerns to FERC on Nov. 27, after the commission notified it of its intent to release documents in the proceeding.

"Release of such information could damage the efficient and competitive operation of PJM markets by facilitating tacit collusion and disseminating substandard fuel cost policy provisions," the Monitor *wrote*. "The release of market sensitive information harms the public interest in maintaining competitive PJM wholesale power markets. That Tenaska Power Services Co. consents does not change the harm to the public interest. … In fact, Tenaska has a conflict of interest because it could benefit from the release of information that harms the public interest by weakening fuel-cost policy standards." ■

PJM News

FERC Denies PJM Monitor's Fuel-cost Policy Complaint

By Christen Smith

FERC last week denied a complaint from PJM's Independent Market Monitor that alleged the RTO erred when it decided against penalizing Tenaska Power Services last year over supposed fuel-cost policy (FCP) violations (*EL19-27*).

The commission said it agreed with PJM's interpretation of Tenaska's FCP that allowed it to use third-party quotes for natural gas when the data it generally relies upon to calculate its energy offers are unavailable — as it was on Jan. 6, 2018.

"PJM reasonably found that Tenaska did not violate its FCP by using third-party quotes to develop natural gas costs when a lack of liquidity prevented the use of its more specific fuel-cost methodologies," FERC wrote in its order. "The language in the Operating Agreement further supports the reasonableness of PJM's conclusion that no violation of the FCP took place, as the lack of market liquidity is a market condition that permits the use of third-party quotes such as the [Intercontinental Exchange] data provided by Tenaska."

The Monitor had interpreted the language of the FCP to prohibit Tenaska from making offers under such conditions — a choice that would leave the dual-fuel Brandywine Power Facility in Prince George's County, Md., subject to nonperformance penalties should extreme weather conditions disrupt its fuel oil supply, Tenaska said. In defense of its actions, Tenaska had pointed to a statement from the FCP that says, "under a set of defined market conditions, natural gas costs may be based on independent third-party quotes."

PJM asked FERC to dismiss the complaint in January 2019 on the grounds that the Monitor lacked the authority to override the RTO's interpretation of Tenaska's FCP. Ultimately, in a separate docket, FERC reaffirmed the Monitor's right to protest FCPs. (See *FERC Upholds Monitor's Right to Protest Fuel-cost Policies* and *Another Win for PJM Monitor on Fuel-cost Policies*.)

But FERC agreed with PJM's decision not to penalize Tenaska, writing Thursday that the company "had a range of potential third-party quotes from which to choose and opted to rely on those on the lower end of the range."

"The Market Monitor provides no basis for establishing this was an unreasonable choice under the circumstances presented in this case," the commission wrote. "Thus, we conclude that PJM acted reasonably in finding that Tenaska acted in accordance with its FCP.

"We recognize that illiquid market conditions can present challenges in calculating accurate fuel costs," the commission added. The ruling advised PJM stakeholders to continue to refine FCPs "to clarify processes for determining how a seller will develop its cost to address a wide array of market conditions, including illiquid conditions, consistent with PJM's Operating Agreement requirements."

The ruling comes just four days after the commission posted a mostly unredacted *version* of Tenaska's January response to the Monitor's complaint, including the FCP in use Jan. 5-6, 2018, when the alleged violations occurred. (See related story, *FERC Releases Documents in PJM Fuel-cost Dispute*.) ■

FERC dismissed the Monitor's complaint against PJM for not penalizing Tenaska Power Services last year over a supposed violation of its fuel-cost policy. | *Brandywine Power*

FERC Extends PJM MOPR to State Subsidies

Existing RPS Resources Exempt

Continued from page 1

efficiency and storage resources; and existing self-supply resources. Federal subsidies would not trigger the MOPR.

Resources not eligible for exemptions can seek unit-specific exemptions by demonstrating their individual costs.

The commission said it chose an expanded MOPR rather than PJM's resource carve-out (RCO) and extended RCO proposals, which it said would distort the markets.

'Level Playing Field'

In remarks at the commission's open meeting Thursday, Chatterjee said the order will ensure the capacity market remains competitive "by establishing a level playing field and being resource-neutral."

"I recognize, respect and support states' exclusive authority to make choices about the types of generation resources that serve their communities. And nothing in this order prohibits them from exercising their jurisdiction over generation decisions. But there can be no question that those choices affect the wholesale markets that we oversee," he said.

The order requires PJM to make a compliance filing in 90 days informing the commission of an updated timetable for its 2019 Base Residual Auction — which was postponed while the case was pending — and of the effect of the ruling on the 2020 auction.

In a separate ruling, the commission also denied rehearing of its 2018 order granting a waiver of MOPR deadlines (*ER13-535-005*). (See *FERC Grants PJM Waiver of MOPR Exemption Deadlines*.)

Slowing Renewables

Glick said the expanded MOPR ruling shows the Republicans' preference for existing generation and desire to slow the transition to renewables.

He recalled that in June, he told the House Energy and Commerce Committee's Subcommittee on Energy that "we need to do something, even if it's the wrong thing" because the long delay in issuing a ruling was creating uncertainty. (See *FERC Probed on RTO Governance, Market Issues*.)

Glick then turned to face his colleagues and said, "Well, Mr. Chairman, Commissioner McNamee, you guys have exceeded my wildest expectations. This is definitely the wrong thing."

He said the order's definition of state subsidy is overly broad and would include all future self-supply generation and resources in states that participate in the Regional Greenhouse Gas Initiative, which include Maryland and Delaware in PJM. New Jersey is planning to rejoin RGGI and Pennsylvania is considering joining. (See *Pennsylvania Governor Signs RGGI Executive Order*.)

"From now on, every single time a municipal utility or electric co-op in the PJM region decides to build a generating facility, that facility will be subject to the MOPR," Glick said. "This blows up the entire business model, as I understand it, of munis and co-ops."

The order defined subsidies as including direct or indirect payments by states, subdivisions of states and co-ops formed under state law, related to the procurement of energy or capacity or used to support the construction or operation of capacity resources.

Glick said that although the order makes no attempt to quantify the impact of expanding the MOPR, his staff's "back of the envelope" estimate is that the expansion will initially boost annual capacity costs by at least $2.4 billion, with larger increases in later years. A $2.4 billion increase would represent 25% over the 2018 BRA, which resulted in total procurement of $9.4 billion for the 2021/22 delivery year. The capacity market represented about 20% of wholesale electricity costs in 2018.

Glick said the estimate doesn't include the impact of states continuing to sponsor resources that won't clear in the capacity auction, resulting in more excess capacity than PJM — which expects a 15.5% reserve margin in 2020 — has today.

By requiring administratively determined minimum prices, Glick said, the commission is undermining competition and creating "opportunities … for generators to manipulate the prices."

"If you are not MOPR'd, or if you're not MOPR'd a lot compared to some of your other competitors, you're going to increase your bid up to the level of everyone else's MOPR," he said. "But there's nothing in this order that says we're going to give the Independent Market Monitor or PJM or anybody else additional authority to ensure that you're not manipulating the market. We're just making sure we have a price floor and not a price cap."

Glick said the commission's rejection of the resource-specific fixed resource requirement (FRR) alternative means the commission is not trying to accommodate state policy preferences.

"It's pretty clear that there's a preference for existing generation versus new generation. … It's a preference to maintain the status quo and stunt the transition to the clean energy future that states are pursuing and that consumers are pursuing."

He acknowledged PJM's 5,000 MW of existing renewables will be exempt from the MOPR.

FERC Commissioner Richard Glick (center) holds a press conference, with legal adviser Matthew Christiansen and Technical Adviser Pamela Quinlan. | © *RTO Insider*

"What they don't tell you is there are another 38,000 [MW] of new renewable facilities that haven't been built yet that won't be exempt," he said, referring to the amount of generation needed to meet PJM states' RPS targets and renewable goals.

Won't 'Destroy PJM'

McNamee rejected Glick's dire predictions. "Despite the rhetoric of the dissent, this is not going to destroy PJM," he said.

He denied the Republicans were trying to protect uneconomic fossil fuel resources, noting that wind and solar power have become increasingly competitive even without state subsidies.

In a press conference after the meeting, Chatterjee said the idea that the order was intended to prop up coal plants was "completely unfair. … This is a market-based approach, not a partisan or a political one."

Chatterjee also rebutted Glick's contention that the order could result in states leaving PJM. "For folks who are concerned that this could potentially lead to unraveling the capacity markets, I will tell you this is an attempt on our part to protect and to save the capacity markets. I can almost assure you that had no action been taken, the capacity markets absolutely would have unraveled.

"[Glick] offers criticism to the approach that we have taken, but he has offered no solution other than the status quo, which PJM itself said was unsustainable," he continued.

"I would love to have the opportunity to write the orders [rather] than them being presented to us as a fait accompli," Glick responded in his own news conference. "But ... I think the first thing you need to do is see if there's a problem. ... The chairman said the commission never even looked at cost: whether this proposal was too costly or whether the existing methodologies are price-suppressive. There's nothing in the record ... to show that there's a problem." Glick also reiterated his concern about states pulling out of the capacity market. "I'd say the chairman maybe needs to spend more time … with state commissioners, because they are extremely worried about this, and they think this is a commission run amok."

Reaction

PJM General Counsel Christopher O'Hara, who attended the FERC meeting, declined to comment on the ruling, as did Craig Glazer, the RTO's vice president of federal government policy. The RTO later issued a statement saying it will discuss the order and its impact with stakeholders beginning at the Jan. 8 Market Implementation Committee meeting.

Stakeholders at Thursday's Markets and Reliability Committee meeting were guarded in their reactions, noting they had not seen the order, which wasn't released until late in the afternoon.

That didn't stop others from weighing in, however.

The Electric Power Supply Association applauded the ruling, saying it "bring us closer to building a durable and sustainable market design that meets the needs of the 21st century."

EPSA CEO Todd Snitchler said that despite complaints about PJM's capacity market, "centralized procurement has delivered positive results for consumers and shouldn't be minimized or abandoned."

Glen Thomas, president of the PJM Power Providers Group (P3), said, "It is imperative that PJM, FERC and the PJM stakeholders work quickly to re-establish PJM's capacity auctions so that stability and predictability can return to PJM's markets. ...

"Regulatory direction related to the impact of state policy decisions on wholesale markets has been sorely missing, and P3 is optimistic that today's order will provide that direction," he said.

Coal lobby ACCCE called the order "a significant step in the right direction" but said it doesn't fix other market flaws that it said were contributing to the loss of coal-fired generation, calling for ways to value "fuel security ... and other resilience attributes."

The American Wind Energy Association said the decision "threatens states' rights and hinders their ability to bring more clean energy to their communities."

The Sierra Club called it "disastrous," saying it will "essentially exclude new renewable energy resources from the PJM capacity market" and increase fossil fuel emissions. It also said it would add almost $6 billion in annual costs, citing a Grid Strategies *study*. (See *MOPR Impact Study Ruffles Feathers Ahead of FERC Ruling*.)

"FERC's decision doesn't solve any problems; it creates more of them, and will likely lead to an exodus of states from the PJM capacity market for good," said Mary Anne Hitt, senior director of the Sierra Club's Beyond Coal campaign.

The American Council on Renewable Energy (ACORE) called the order "an early Christmas gift to the fossil fuel industry."

FERC Chief of Staff Maria Farinella talks with PJM General Counsel Christopher O'Hara after the commission's open meeting had concluded. | © *RTO Insider*

"ACORE is reviewing the implications of this order and our available options, but what is clear today is that FERC overstepped its authority with a decision that will ultimately lead to more pollution and higher electricity rates for consumers," CEO Gregory Wetstone said.

Exelon, which has won state subsidized zero-emission credits for two nuclear plants in Illinois and is seeking similar supports for four other nuclear plants, said the order "completely undermines state clean and renewable energy programs, and will cost thousands of jobs, increase air pollution and unnecessarily raise electricity bills by $2.4 billion annually. Given this stunning decision, it's critical that PJM now give states enough time to react and protect families and businesses."

The New Jersey Board of Public Utilities said the order "shows a callous disregard for the health and safety of the residents of New Jersey and the other impacted PJM states."

"We anticipate it will make it more difficult for the state to affordably address climate change through the competitive markets. The state of New Jersey will not be deterred as we move forward to implement Gov. [Phil] Murphy's vision for 100% clean energy by 2050 as we strive to do all we can to combat the climate change crisis."

"FERC issued pretty much the worst-case order," the Natural Resources Defense Council's Tom Rutigliano tweeted. "PJM will now have tto plan the power grid pretending state-supported renewable and nuclear resources don't exist. This is the beginning of the end of capacity markets."

Energy Secretary Dan Brouillette praised FERC for "strong action to support competition in electricity markets so all of America's abundant energy sources compete on an even playing field." ■

Christen Smith contributed to this article.

PJM News

PJM TOs Challenge Monitor's Competitive Tx Role

By Christen Smith

VALLEY FORGE, Pa. — PJM stakeholders endorsed manual language Thursday that memorializes the Independent Market Monitor's role in analyzing competitive transmission proposals.

But incumbent transmission owners contend the revisions have no basis in Attachment M of PJM's Tariff and undermine the yearslong vetting process stakeholders undertook to fine-tune cost-containment language for Manual 14F. (See *PJM TOs Wary of Cost Containment Rules*.)

Last week, PJM posted manual *revisions* that added two sentences outlining the Monitor's ability to access data contained within competitive bids for transmission projects and to perform independent analysis using that information. Incumbent TOs took particular issue with the qualifying clause of the revisions that cite Attachment M of the Tariff as the prevailing source authorizing the Monitor's involvement in the process.

"Attachment M is silent on what the Market Monitor has access to as it relates to the competitive process," said Amber Thomas, PPL's utility regulatory specialist. "Where in the Tariff does it say in Attachment M that the IMM has access to this data? The Attachment M does not say that. To make these big policy changes in Manual 14F to codify something Attachment M does not say does not sit well with PPL."

The revisions, borne out of a stakeholder motion endorsed by the Markets and Reliability Committee last year, will codify the framework the RTO will use to evaluate competitive transmission projects. (See "PJM Unveils Flat Fee Cost-containment Plan," *PJM PC/TEAC Briefs: Aug. 8, 2019*.) Since implementation of FERC Order 1000 in 2014, PJM has reviewed 850 competitive proposals, of which less than 20% included cost-commitment provisions.

Interim PJM CEO Susan Riley | *© RTO Insider*

Interim CEO Susan Riley clarified Thursday that the revisions represent a compromise about the Monitor's collaborative role and don't obligate PJM to share its project analyses, just the data used to support their conclusions.

PJM's Markets and Reliability Committee debated manual language that detailed the role of the Independent Market Monitor in evaluating competitive transmission proposals. | *© RTO Insider*

"The intent is not to have an oversight process over the work that PJM is doing, merely to allow an independent review," she said. "I don't think it's a big give. [The Monitor] does not have approval authority over these projects as to whether they go forward or not. He will just get the data."

Monitor Joe Bowring said Attachment M, part V of the Tariff "makes clear that the IMM's access to data is all inclusive."

"Attachment M is also quite clear and explicit that the IMM has authority to address issues of competition in PJM markets. Competition to build transmission facilities is clearly part of PJM markets," Bowring added. "These sentences in the manual don't reflect a compromise; they reflect what our duties are as defined by the Tariff. Under Attachment M, the IMM has the authority to look at competitive issues in the PJM markets."

Alex Stern, PSE&G | *© RTO Insider*

The overtures from PJM and the IMM did little to ease incumbent TOs' concerns. Alex Stern, manager of transmission strategy and policy for Public Service Electric and Gas, questioned PJM's "procedural gymnastics" in bringing the revisions forward with no opportunity for review or vetting and in defiance of a stakeholder vote overwhelmingly endorsing language that did not include reference to the Monitor.

Stern suggested the MRC instead approve an earlier *version* of Manual 14F language that excluded the two sentences regarding Attachment M. He said that language was properly vetted by the Planning Committee and through special sessions, as required by the original MRC motion, unlike the revisions PJM and the Monitor crafted and posted online just last week.

He added that expanding the scope of the revisions to include the Monitor's role was not a part of the discussion until recently — and that it was not driven by stakeholder interest but rather by the Monitor itself. Even so, the recent conversations at the MRC never referenced Attachment M, Stern said.

"The marketplace is not made up by what PJM and the IMM come up with in agreement on their own," he said. "It's legally suspect and raises a whole host of questions."

Bowring called Stern's accusations "demonstrably false," pointing to special PC sessions discussing his role in the process and corresponding manual language dating back to August.

"The role of IMM was identified explicitly by a vote of the MRC more than a year ago at the beginning of this process. The specific language about the role of the IMM has been discussed for months in this process," he said. "In fact, language about the IMM role in the manual was jointly drafted by the IMM and PJM but was removed months ago at the insistence of the TOs."

Ken Seiler, PJM's vice president of planning, reiterated the RTO's interpretation of the Tariff, even if it doesn't spell out exactly what incumbent TOs say it should.

"As I understand it, there's language in the Tariff in Attachment M that specifies [the Monitor's] roles and responsibilities," he said. "Is it explicit? No. The Tariff is high level. We would try to fulfill those [data] requests based on the spirit of what's in the Tariff."

PJM stakeholders overwhelmingly approved the PJM-Monitor language with a sector-weighted vote of 3.92 to 1.08. ■

PJM News

FERC Conditionally Accepts JCP&L Rate Request

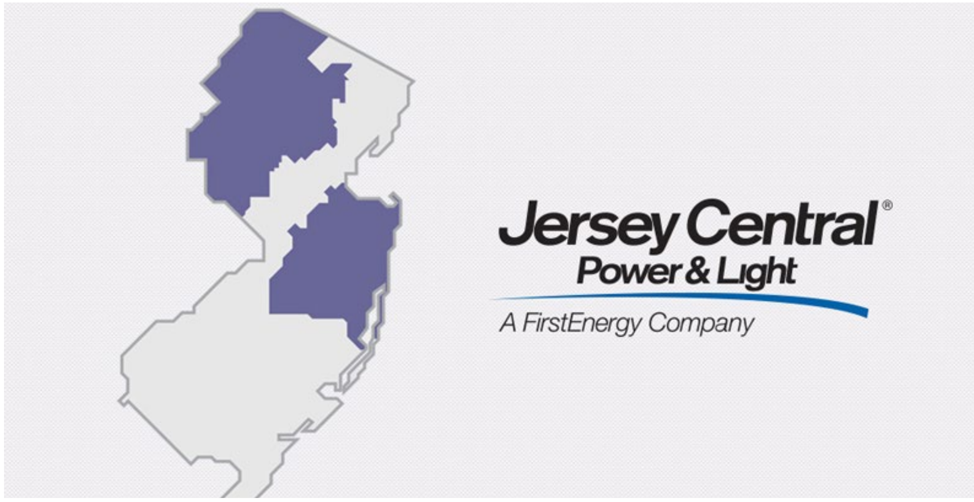
FERC last week conditionally accepted Jersey Central Power & Light's proposed rate request, subject to refund following hearing and settlement judge procedures (*ER20-227*).

The commission accepted the FirstEnergy operating company's request for a 50-basis-point adder on its PJM base return on equity. However, FERC said its preliminary analysis found JCP&L's request may be unjust and unreasonable.

FERC said the filing raised issues of material fact — including the determinations of base ROE and capital structure and the treatment of excess accumulated deferred income taxes — that couldn't be resolved based on the record before it and ordered settlement procedures.

JCP&L filed its request in October to replace its current transmission revenue requirement with a new formula rate and associated protocols, effective Jan. 1, 2020.

The New Jersey Division of Rate Counsel, the state's Board of Public Utilities and the Public Power Association of New Jersey opposed JCP&L's request. They argued that the utility did not correctly apply the ROE methodology, resulting in an ROE above the applicable portion of the zone of reasonableness, and that it did not "sufficiently" prove that the adder will benefit ratepayers.



JCP&L's service territory | *FirstEnergy*

The groups also argued that JCP&L incorrectly presented its capital structure as a net long-term debt figure, ignoring FERC's requirement of a gross long-term debt figure instead.

The commission found the requested adder to be consistent with Section 219 of the Federal Power Act and its own precedent. It conditioned its approval on the adder being applied to a base ROE that has been shown to be just and reasonable and subject to the resulting ROE being within the applicable zone of reasonableness, as may be determined in the settlement proceeding. ■

— Tom Kleckner


JCP&L linemen at work | *FirstEnergy*

FERC Lets Original PJM Stability Method Stand

By Michael Brooks

FERC on Thursday backtracked on several Tariff provisions it directed PJM to include in its implementation of a new cost allocation method for transmission projects that address stability issues (*EL15-95-005, ER19-1501*).

The commission granted rehearing of its Feb. 28 order accepting PJM's stability deviation method for the limited purpose of removing the provisions from the compliance filing the RTO submitted in April. It directed PJM to refile its Tariff revisions without the provisions, leaving the new method as originally proposed.

The stability deviation method identifies the loads that would be most impacted by a stability disturbance — and thus benefit most from transmission projects that address stability-related issues — by measuring the voltage angular deviations during a simulated worst-case fault. Load buses with a deviation of less than 25% of the highest deviation would be excluded from the cost allocation. (See *FERC: Stability Deviation Method Best for Artificial Island*.)

In its original proposal, however, PJM identified a possible flaw in this plan: Once in service, the new transmission facility could address all stability issues, making it impossible to measure any angular deviations in a simulation. Several transmission owners also noted that the 25% threshold meant that under certain conditions, some deviations would be excluded from the cost allocation.

FERC directed PJM to include language to take the new facility out of the analysis if it resulted in deviations too small to measure when running the simulation. It also directed language that would allow PJM to adjust the 25% threshold as necessary.

In its April compliance filing, however, PJM said it had done further analysis and determined "that removing the stability upgrade would cause the model to go unstable and, therefore, fail to provide any meaningful information upon which to base the cost allocation." Meanwhile, TOs American Electric Power, Dominion Energy, Duke Energy, FirstEnergy and PPL complained that the discretionary threshold provision would allow the RTO "to unilaterally determine the rate design under the PJM Tariff to recover the costs of a stability project based solely on PJM's own discretion and with no approval or participation by" TOs.

To address both concerns, PJM asked FERC to delete the two provisions for now and give it some time to develop more Tariff revisions. FERC agreed.

"Accounting for these changed perspectives, we grant rehearing and remove both the deviation measurement provision and the discretionary threshold provision," the commission said. It gave the RTO 30 days to refile its original proposal. ■

Artificial Island in New Jersey, site of the Salem and Hope Creek nuclear plants. How to allocate the costs of transmission facilities meant to address stability limits on generation from the plants led to the creation of the stability deviation method. | *BHI Energy*

PJM News

PJM Fuel Security OK for Now, Stakeholders Decide

By Christen Smith

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee agreed to sunset the Fuel Security Senior Task Force on Thursday after determining the RTO seems prepared enough, for now, for any potential reliability threats.

Except, some utilities argued, PJM stakeholders should do more than the "minimum" required to protect against fuel supply issues — especially when generators can signal a deactivation in as little as 90 days ahead of time.

The MRC approved the task force's *issue charge* in March to investigate what market responses to conditions could lead to fuel insecurity and assessing whether the current market construct is sufficient to cure the problem. (See *PJM Stakeholders Reluctantly OK Fuel Security Initiative*.)

PJM Director of Energy Market Operations Tim Horger *said* Thursday that stakeholders could decide either to maintain the status quo with periodic reviews of the RTO's fuel security or pursue more aggressive paths to implement market, operational and planning changes. A nonbinding poll of 204 stakeholders determined that 74% agreed nothing more needed to be done.

Exelon, FirstEnergy and Dominion Energy were not among those in favor.

"These retirements can cause a significant shift on installed reserve margins," said Sharon Midgley, Exelon's director of wholesale market development. "Generation owners have a line of sight into how resources are doing from an economic standpoint that PJM does not have."

Midgley added that resilience-based events cannot be averted by market-based solutions developed after the fact, so it would be prudent to initiate a discussion on potential criteria or solutions in 2020, so planning could occur in advance of any issue.

Paul Sotkiewicz, president of E-Cubed Policy Associates and PJM's former chief economist, said because of the three-year forward structure of the capacity market, the average retirement notice falls somewhere between 30 and 33 months. He said that PJM's analysis — which included 324 different scenarios — shows "there's no urgent or imminent problem."

Bob O'Connell, director of regulatory affairs and compliance for Panda Power Funds, pointed to yearly reports from Monitoring Analytics, PJM's Independent Market Monitor, that provide a high-level view of generator economics in the RTO.

"I think the Market Monitor does an excellent job of highlighting generation at risk in its annual State of the Market Report," he said. "While it may be done at a rough level based on types of assumptions that need to be made, I think it does give a pretty good indication of where the economics are regarding retirement."

The utilities disagreed, arguing that the Monitor does not take into account risks associated with plant operations and presumes that PJM's short-run capacity market outcomes are sufficient to benchmark the prudence of continued investments in long-lived assets.

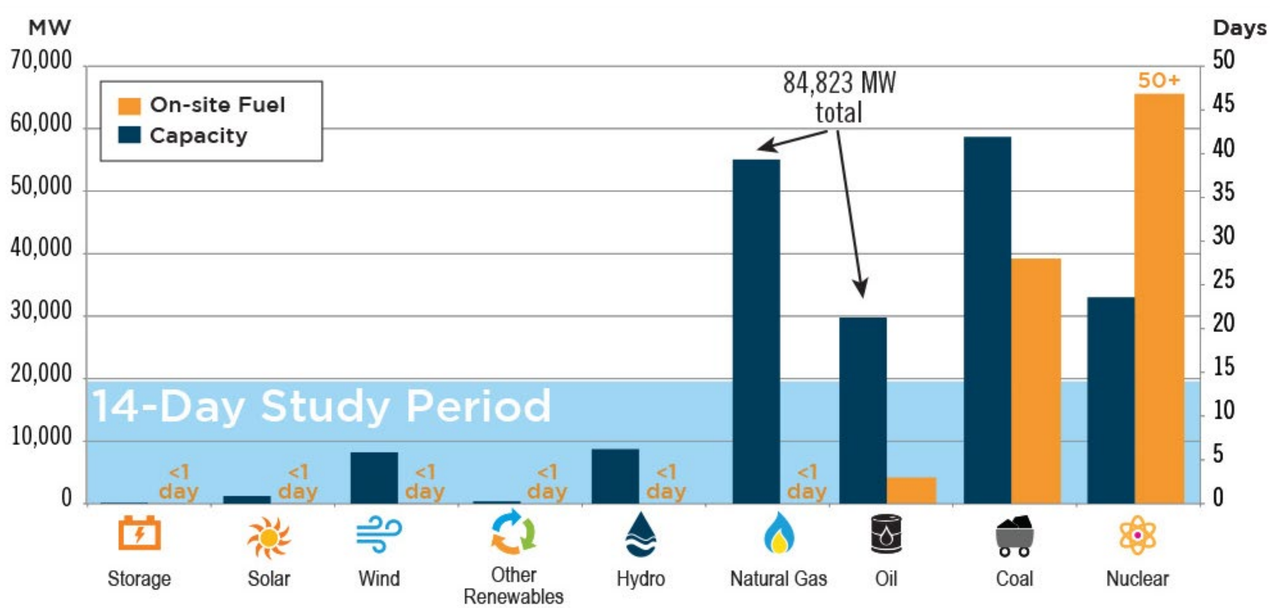
Jim Davis, an electric policy market consultant for Dominion, said the average retirement notice doesn't tell the full story of PJM's changing resource portfolio.

"Even though the average is three years in advance, that could be accelerated in the future given the advancement of renewables," he said. "From our experience, pipelines are being constrained more frequently [than before]."

Susan Bruce, of the PJM Industrial Customer Coalition, said that perhaps the idea of just monitoring the situation, as part of the status quo path, "might not be the right phraseology."

"It has a more passive approach than many from the outside looking in might expect," she said, mentioning that some continued reporting to stakeholders might help ease concerns.

The MRC approved the status quo path in a sector-weighted vote of 4.5 to 0.5. A motion from the D.C. Office of the People's Counsel to sunset the task force was endorsed by acclamation, with objections from Exelon, Dominion and FirstEnergy. ■



Fuel security analysis scope | *PJM*

PJM News

PJM MRC Briefs

FTR Credit Rules Endorsed

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee on Thursday endorsed the first round of credit policy revisions to come out of a task force formed in the wake of GreenHat Energy's default on its 890 million MWh financial transmission rights portfolio.

PJM said the recommendations, initially presented at the October MRC meeting, will improve its credit risk policies after the Financial Risk Mitigation Senior Task Force delegated a more holistic FTR market review and possible design changes to a separate Market Implementation Committee task force. (See "FTR Market Rule Changes," *PJM MRC Briefs: Oct. 31, 2019*.)

One proposed change includes hosting five long-term FTR auctions a year, instead of three, in order to increase oversight and visibility into portfolio conditions so that more collateral can be collected if necessary. A second would alter the structure of Balancing of Planning Period auctions so that participants can buy and sell in any month of the year, rather than being limited to a specific quarter.

Stakeholders had voiced concerns about the auction restructuring crossing into market design territory, but they ultimately agreed to move forward with the option of revising the changes during the forthcoming MIC review. (See "FTR Vote Deferred," *PJM MRC/MC Briefs: Dec. 5, 2019*.)

"I assure that no changes we are making here preclude us from making additional changes when we do the full FTR review," said interim CEO Susan Riley, who had urged stakeholders to endorse the revisions as a "really big win."

PJM's Markets and Reliability Committee met Dec. 19 at the Conference and Training Center in Valley Forge, Pa. | © *RTO Insider*

Competitive Transmission Proposal Fee

Stakeholders endorsed PJM's new fee structure for its evaluation of competitive transmission proposals.

The new framework PJM wants to use will involve charging a $5,000 nonrefundable flat fee to all developers who submit competitive proposals. Itemized study costs will be added as necessary. Mark Sims, PJM's manager of infrastructure coordination, said the intent is to bill projects that incur the extra expense. (See "PJM Unveils Flat Fee Cost-containment Plan" in *PJM PC/TEAC Briefs: Aug. 8, 2019*.)

Sims previously told the Planning Committee that PJM's old tiered approach, approved in 2014, doesn't account for the increased cost of the new comparison framework that involves an independent consultant's review and legal and financial analyses. (See "New Fee Structure for Cost Containment Needed," *PJM PC/TEAC Briefs: May 16, 2019* and "PJM Developing Hybrid Fee Structure," *PJM PC/TEAC Briefs: June 13, 2019*.)

Real-time Values

Stakeholders endorsed PJM's *issue charge* that would address *concerns* over the misuse of real-time values (RTVs) in parameter-limited scheduling (PLS). (See "Real-time Values, Parameter-limited Schedules," *PJM MRC Briefs: Dec. 5, 2019*.)

PJM *said* that some capacity generators use RTVs to override unit-specific parameters for inappropriate reasons, causing unnecessary confusion during dispatch.

The original intent of RTVs was to provide a way for generation operators to communicate current operating capability to PJM if their resources couldn't meet their unit-specific parameter limits or approved exceptions. Generators opt to use RTVs and forfeit operating reserve credits and make-whole payments as a result.

Except, some generators consistently use RTVs to increase notification time on PLS "to reflect the decision not to staff the resource during hours they project the resource will not be economic," PJM said. The operational impacts mean that resources called in real time based on their schedules cannot perform as expected.

The RTO will commence a special session of the MIC in 2020 to study the problem and recommend solutions.

Parameter-limited Scheduling Fix

The MRC endorsed revisions to the Operating Agreement and Tariff that align it with PJM's actual implementation of PLS.

The revisions correct language *errors* introduced with the implementation of Capacity Performance that caused the RTO's practice regarding PLS to contradict its own rules and conflict with other governing documents, PJM told the MIC and MRC earlier this month. The

PJM News

Monitor said, however, that PJM should simply follow the language set out in the Tariff instead of revising the document to fit its current practice. (See "Parameter-limited Schedules, *PJM MIC Briefs: Dec. 11, 2019*.)

Stakeholders approved PJM's revisions in a sector-weighted vote of 4.67 to 0.33.

Modeling Generation Senior Task Force Recommendations

The MRC partially endorsed *recommendations* from the Modeling Generation Senior Task Force that can be implemented in the near term while PJM focuses on completion of its next generation energy market (nGEM).

The MGSTF, assembled in 2017, developed the solutions to improve resource modeling for "complex resources" in PJM's market clearing engines, including combined cycle units, coal units with multiple mills and pumped hydro.

The endorsed recommendations include:

- adding additional segments to the energy offer curve beyond the 10 currently available to increase resource configuration modeling capabilities; and
- providing market participants with the ability to submit hourly differentiated segmented ramp rates for resources in both the day-ahead and real-time markets.

A third recommendation to implement "soak time" modeling of resources was deferred until next month at the request of stakeholders who were concerned about the time and energy it would require. "Soak time" refers to the minimum number of hours a unit must run, in real-time operations, from the generator breaker closure until the time the unit is dispatchable.

FTR Market Update

PJM Chief Risk Officer Nigeria Poole Bloczynski told the MRC that the RTO should do more to assess market participant risk profiles and enhance its collateral practices across all markets — not just FTRs.

"I think it's best practices to evaluate risk profiles for all participants," she said. "This is phase 1 of what I think should be a prudent practice of looking at our policies every year or every other year to make sure our policy isn't static while the market continues to change."

PJM hired Bloczynski in July after an independent probe of the GreenHat default found the RTO's executive team lacked credit expertise. She said Thursday she's hiring four additional staff in her department, including a manager of credit risk and trading risk, and challenging current employees to automate as many processes as possible.

As far as expanding the application of credit risk management beyond the FTR market, PJM will bring corresponding Tariff and OA changes to the MRC for a final vote in January.

Manuals Changes Endorsed

- Manual 13: Emergency Operations, incorporating event analysis *updates*.
- Manual 14D: Generator Operational Requirements, *adding* guidance associated with distributed energy resource ride-through.
- Manual 27: Open Access Transmission Tariff Accounting, *addressing* the implementation of the annual calculation of the border rate and the impact on firm point-to-point transmission service charges. ■

— Christen Smith

SPP News

FERC Denies Rehearing of SPP Exit Fee Decision

By Tom Kleckner

FERC last week rejected a request by SPP and its load-serving entities to rehear its April order that eliminated the RTO's membership exit fee for non-transmission owners (*EL19-11*).

The commission also rejected SPP's alternative proposal to lower the fee to $100,000. Rejecting the proposal without prejudice, FERC ordered the grid operator to submit another proposal "that adequately explains" why the exit fee for non-TOs is just and reasonable and "not a barrier to membership … and not excessive as a means of ensuring stability in membership and members' financial commitment." (See ***SPP Proposes to Drop Exit Fee to $100K***.)

"Any future exit fee proposal should ensure that [non-TOs] pay a smaller exit fee than transmission owners, regardless of whether the [non-TO] is also [an LSE], and that non-transmission-owning load-serving entities pay an exit fee similar to that paid by other [non-TOs]," the commission wrote.

In affirming its previous decision, FERC denied contentions by the RTO and its LSEs that it erred in finding that the exit fee is so high that it presents a barrier to membership to non-TOs and results in cost shifts among SPP's members. (See ***FERC Tells SPP to End Exit Fee for Non-TOs***.)

The commission said exempting non-TOs from the exit fee does not unfairly shift costs to remaining SPP members because non-TOs "have less of an impact on the system when they exit than transmission owners do and SPP can still recover these costs through administrative fees."

The commission determined in April that the exit fee "was not needed to maintain SPP's financial solvency or to avoid cost shifts and was excessive as a means for ensuring the stability of SPP's membership and members' financial commitment." FERC did agree "some level of exit fee" is necessary for non-TOs.

The proceeding stems from a complaint last year by the American Wind Energy Association and the Advanced Power Alliance, which have long argued against the exit fee. The fee is defined as the sum of the withdrawing member's obligations at the time of withdrawal, including any unpaid dues or assessments, and the member's share of SPP's outstanding long-term financial obligations. SPP estimates the fee for an entity without load is $631,915 — nearly twice the estimated $327,191 fee when FERC approved it in 2006.

The decision was a welcome bit of good news for AWEA and APA. Amy Farrell, AWEA's senior vice president of government and public affairs, said the order partially offset FERC's ruling favoring existing generation in the PJM capacity market. (See related story, ***FERC Extends PJM MOPR to State Subsidies***.)

"The only glimmer of light … was FERC's reaffirmation requiring [SPP] to eliminate the membership exit fee, allowing for a more inclusive stakeholder process that will lead to better outcomes for consumers," Farrell said in a statement. ■

| SPP

Company Briefs

GE Sells Stake in US Wind Farms Portfolio

Harbert Management Corp. last week announced the acquisition of 80% of an 812-MW portfolio of U.S. wind farms from a joint venture between General Electric and Enel Green Power. Harbert is buying the projects through its Gulf Pacific Power unit. Financial terms were not disclosed.

Enel and GE formed the joint venture known as EGPNA Renewable Energy Partners in 2015, but GE recently wanted out as the company refocuses on core business ideals and the wind market repositions ahead of the anticipated phase-down of the federal tax credit.

More: *GreenTech Media*

FirstEnergy Solutions Announces New Headquarters

FirstEnergy Solutions, which will soon become Energy Harbor, said last week it plans to move its headquarters to the former Akron Post Office building during the first quarter of 2020.

The building is recognized as one of the cornerstones of Akron, Ohio's historic district. It was completed in 1929 and, following reconstruction, will house roughly 150 employees.

More: *FirstEnergy Solutions*

IBM's New Battery Design Taps into Seawater

IBM, along with Daimler AG's Mercedes-Benz, Central Glass and Sidus, said last week they have created a battery design that uses materials extracted from seawater and requires no cobalt.

Although IBM may not make a product using the design, it said the technology has proven it can outperform lithium-ion batteries in cost, charging time and energy efficiency. IBM Research Vice President Jeff Welser said the goal is to have a working prototype within a year.

More: *Reuters*

NYISO Posts New Wind Record

NYISO set a new wind generation record on Dec. 14, generating 1,675 MW during the 11 p.m. hour. It broke the previous mark of 1,651 MW set on April 26 of this year.

At its peak that night, wind production provided 11% of all energy generation in New York state.

More: *NYISO*

Xcel Energy Buys Lake Benton Wind Energy Center

Xcel Energy last week announced it has purchased the 100-MW Lake Benton II Wind Energy Center located in Pipestone County, Minn.

A NextEra Energy Resources subsidiary had owned and operated the project for the last 20 years and recently updated the project with new technology that will increase the energy the it will deliver. It currently features 44 General Electric turbines.

More: *North American Windpower*

LS Power to Acquire EVgo

LS Power last week announced that it had signed a definitive agreement to acquire EVgo, "the most reliable public fast charging network for electric vehicles," from Vision Ridge Partners.

EVgo will continue to operate as a standalone entity under the LS Power umbrella of companies. The transaction is expected to close in early 2020, and financial terms were not disclosed.

"This acquisition provides LS Power the opportunity to support the continued expansion of EVgo's unmatched charging infrastructure platform, already present in 66 metropolitan markets, and invest further in the company's growth as the market for EVs continues to expand," said David Nanus, co-head of private equity at LS Power.

More: *LS Power*

Federal Briefs

Trump Signs $1.4T Spending Bills Eliminating Some Tax Credits

President Trump on Friday signed two spending packages totaling $1.4 trillion that averted a government shutdown at midnight but did not include extending tax credits to solar and electric vehicles, among other resources and technologies.

Wind developers, however, can now qualify for the production tax credit through 2020 — a year longer than anticipated. Tax credits for biodiesel fuel and energy-efficiency projects were also extended. The *bill* that covered energy-related spending also revived expired tax breaks for geothermal and electric scooters.

But offshore wind developers would not get the same boost. Energy storage was also left out of the last-minute deal between House Democrats and the White House, considered a surprise by some observers as the House of Representatives had impeached the president just two days earlier.

Democrats did manage to secure increased funding for the Department of Energy and EPA, which the Trump administration had been seeking to slash. The bill boosts funding for EPA by $208 million and increases funding for basic scientific research at DOE by $415 million.

FERC secured its requested budget of $382 million, an $8.7 million increase over its FY 2019 spending.

Trump signed the bills more than three months into the 2020 fiscal year; the government had been operating under two continuing resolutions since Oct. 1 at FY 2019 levels.

More: *The Hill*; *GreenTech Media*; *The Washington Post*; *The Wall Street Journal*

Blowout Turned Ohio Natural Gas Well into Methane 'Super-emitter'

Scientists confirmed last week that a 2018 blowout turned XTO Energy's natural gas well in eastern Ohio into a methane "super-emitter," leaking more of the greenhouse gas in 20 days than all but three European nations emit over an entire year.

The well owned by the ExxonMobil subsidiary, which had been fracked before the blowout, took nearly three weeks to get under control and spewed 60 kilotons of methane into the atmosphere. It was the first time methane from an oil or gas incident had been detected and quantified via satellite during a routine survey.

More: *The Washington Post*

New Report Says Energy Efficiency Efforts Have Made Impact

An "Energy Efficiency Impact Report" from the Alliance to Save Energy, the American Council for an Energy-Efficient Economy and the Business Council for Sustainable Energy quantifies the scale of U.S. efficiency investments made over decades and their impacts. The report notes the investments have prevented a 60% increase in energy consumption and carbon emissions since 1980 and are responsible for half of the CO_2 reductions in the U.S. power sector since 2005.

Looking into the future, improvements using existing technologies could deliver more than 40% of the carbon reductions globally to meet the targets under the 2015 Paris Agreement on climate. However, the report says the U.S. is not on this track to achieve these reductions, and even risks sliding backward. While spending on energy efficiency has increased slightly from 2016 to 2018, estimated domestic energy efficiency investments have fallen by 18%, as energy intensity in the U.S. worsened slightly in 2018.

More: *Facility Executive*

NRC Gives Permit for Factory-built Nuclear Reactor

The Nuclear Regulatory Commission last week approved the nation's first preliminary site permit for the Tennessee Valley Authority for a small modular reactor (SMR) near Oak Ridge, Tenn. The permit gives TVA 20 years to consider building one or more reactors at the site, totaling no more than 800 MW. The decision would depend on energy demand and other economic factors.

The nuclear industry believes a new generation of SMRs using the latest technology could serve as carbon-free alternatives for coal and natural gas plants. However, opponents say regulators are already cutting corners for plants still under development and are moving toward allowing nuclear technology, waste and risks from radiation and terrorism into communities.

The main item of controversy was NRC's agreement to consider waiving a mandate that nuclear plant operators have evacuation routes and other emergency plans in place for a 10-mile zone, but regulators have agreed that full-on emergency planning could stop at a 2-mile zone if it was deemed the radiation risks from a small modular reactor were reduced enough.

More: *The Associated Press*

State Briefs

ARKANSAS

Today's Power Starts Solar Project Co-op in Texarkana

Today's Power Inc., a Little Rock-based solar contractor, broke ground last week on a 1-MW array for Southwest Arkansas Electric Cooperative in Texarkana that is designed to ease peak summer demand.

The project's construction will take place on 8 acres and consist of 3,800 PV panels in a single-axis tracking array. Once the project is finished, only four of the state's 17 cooperatives will be without a TPI-built solar power plant.

More: *Arkansas Business*

CALIFORNIA

Regulators Say PG&E, SCE Can't Raise Profit Margins

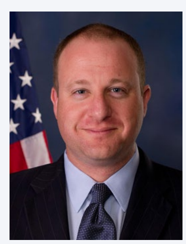
The Public Utilities Commission last week unanimously ruled that profit margins for Pacific Gas and Electric, Southern California Edison, Southern California Gas and San Diego Gas & Electric will remain the same: 10.25%, 10.3%, 10.05% and 10.2%, respectively.

The companies argued that higher profits were needed to keep attracting sufficient capital to fund operations and pointed to the billions of dollars in wildfire liabilities that prompted PG&E to file for bankruptcy, saying investors may need larger returns to justify continued funding. The commission cited Assembly Bill 1054 in its decision, which could give utilities access to funds to help pay for damage from fires ignited by their equipment.

More: *Los Angeles Times*

COLORADO

Governor Signs Executive Order to Make Government More Efficient



Gov. **Jared Polis** last week signed an executive order that aims to reduce greenhouse emissions from state automobiles, reduce state government agencies' and departments' energy consumption, and increase the percentage of renewable electricity used at government facilities. It is the state's latest effort to move toward 100% renewable energy by 2040.

Polis told reporters that the costs will be covered under existing state budgets, and that upfront costs would be covered by future savings. "Each agency will be held accountable" for those goals, he said. "This will produce substantial savings" and reduce the state's electric bill by 15%, he said.

More: *The Gazette*

Xcel Energy Natural Gas Costs Expected to Drop this Winter

Xcel Energy last week filed natural gas rates with the Public Utilities Commission that are 25% lower for the fourth quarter than they were for the same period last year. Because of an abundance of natural gas, the average household will pay $20.18 less a month, according to utility estimates, down from $79.39.

The utility also asked the PUC for a 6.7% increase in electricity rates next year to help upgrade the power grid and fund other improvements.

More: *The Denver Post*

KENTUCKY

PSC to Hire Consultant to Implement Net Metering Statute

The Public Service Commission last week decided to hire a consultant to help with implementing the state's new net metering statute, as the approach will be different than conventional rate proceedings and will have to be created new.

The new law will change how utilities credit their customers for electricity generation on their properties. It says each utility is able to implement rates to recover from its eligible customers all costs needed to serve those customers, but they each will have a different rate determined by the PSC. The consultant is needed to bring "expertise and experience" the commission does not possess and will help it sort through comments during the planning process.

More: *Daily Energy Insider*

MARYLAND

Gov. Hogan Promotes Energy Plan

Gov. **Larry Hogan** last week continued to tout his clean energy plan, entitled the Clean and Renewable Energy Standard (CARES).

Hogan said his bill would be an improvement over the Clean Energy Jobs Act, passed by the legislature that he allowed to become law without his signature earlier this year. His bill would maintain the renewable energy requirements of 50% by 2030 and 100% by 2040, and would stop allowing renewable energy incentives for burning trash or a papermaking byproduct called "black liquor" to generate electricity. However, the plan adds nuclear power.

Hogan said his bill would address the state's credits and how they can be used to subsidize electricity production in other states. He did not explain how his bill would accomplish that, but the Department of the Environment said it would create an additional class of clean energy resource credits that only Maryland-based electricity production could receive.

More: *The Baltimore Sun*

MICHIGAN

PSC Approves Consumers Energy Agreements

The Public Service Commission last week approved two agreements involving Consumers Energy that support the utility's expanding use of renewable sources.

Consumers' settlement with affiliates of sPower Development over four solar power purchase agreements resolved rights and obligations under the U.S. Public Utility Regulatory Policies Act. The second agreement, with General Electric, approved a turbine purchase.

More: *Michigan PSC Settlement Resolves PURPA Clashes*; *Michigan.gov*

MISSOURI

Court OKs Grain Belt Express Line Despite Objections

The Court of Appeals Eastern District last week rejected landowner and farm bureau claims that the Public Service Commission had erred in approving the construction of the Grain Belt Express Transmission line in March.

The PSC's unanimous gave the project a certificate of convenience and necessity, which recognized it as being in the public interest and allowed developers to use eminent domain as needed. Landowners in the line's path, as well as the farm bureau, appealed and argued the PSC had misinterpreted evidence and state utility laws. The line is expected to cross the property of 570 landowners.

"[Missouri Landowners Alliance] has failed to meet its obligation to show by clear and satisfactory evidence that the commission's report and order was not based on competent and substantial evidence on the whole record," Judge Mary Hoff said.

More: *St. Louis Post-Dispatch*

Evergy to Try New Program for Easier Efficiency Upgrades

The Public Service Commission last week instructed Evergy to conduct a one-year pilot program within the next three years that is intended to help renters and low-income residents conserve energy.

For years, regulators have considered an on-bill repayment system known as Pay As You Save (PAYS) and finally approved a $15 million budget for the program as part of energy efficiency features submitted by Evergy. Details such as launch date have yet to be determined.

Under PAYS, a utility provides funds and owns energy efficiency upgrades until they are paid off. Payments are typically spread out over 10 to 12 years and are incorporated into the bill. If a customer moves, the payments and energy savings accrue to the next renter or owner.

More: *Energy News Network*

NEBRASKA

Hamilton County Rejects Wind Towers

The Hamilton County Board of Commissioners last week unanimously rejected a conditional-use permit for a wind project proposed by a Bluestem Energy Solutions subsidiary.

On top of denying the project, which would have consisted of four 2.82-MW General Electric towers, the board created a moratorium on building wind turbines until county staff members can research the impact of wind farms on people's health. Furthermore, Commissioner Roger Nunnenkamp said he felt the burden was on Bluestem to show the farm would not be harmful to anyone's health.

More: *Omaha World-Herald*

NEVADA

NV Energy Fined by PUC

The Public Utilities Commission last week approved a $100,000 fine for NV Energy after the utility failed to comply with orders to set aside $10 million for energy storage system incentives and ordered it to deposit the money in the State General Fund.

Utility filings say the money that should have went to the energy storage systems was paid out to customers through other incentive programs. They also showed NV Energy set aside roughly $5.3 million for the program in June, but it and the PUC were unable to find a solution to the funding shortfall.

More: *Las Vegas Review-Journal*

NEW YORK

Board OKs Wind Project in Broome County

The Siting Board last week voted 5-1 to approve a 124-MW, 27-tower Bluestone Wind project in eastern Broome County and allow Calpine to begin construction. It is the fourth wind turbine project to be approved by the board in the last four months.

By giving its approval, the board rejected a newly adopted zoning law by the town of Sanford that placed restrictions on the project. The board was precluded from considering the law's land use code because it was adopted on Dec. 10, well after formal public hearings on the project. Still, the decision can be appealed within 30 days.

More: *Binghamton Press & Sun-Bulletin*

State Hits Milestone of 2 GW of Solar Capacity Installed

The New York Energy Research and Development Authority last week said 2 GW of solar capacity have been installed across the state, making for a 1,800% growth since 2011.

The 2 GW represents one-third of the capacity needed to achieve a statewide target to install 6 GW of solar by 2025 and supports Gov. Andrew Cuomo's Green New Deal, which aims to have 70% of the state's electricity to come from renewable sources by 2030. Along with the current 2 GW, there are another 1,262 MW of solar projects currently under development.

More: *NYSERDA*

TEXAS

Origis Services Constructing Solar-plus-Storage Operations Center

Origis Services said last week it has begun construction of a large solar and energy storage Remote Operations Centers in Austin. It is expected to be completed in early 2020.

The 365-MW facility will be equipped with a fully NERC critical infrastructure protection remote operations center and will be able to support large utility and distributed solar-plus-storage projects.

More: *Solar Power World*

VERMONT

EV Rebate Program Launched

The state last week launched an incentive program for the purchase or lease of new plug-in EVs (PEVs) with a total of $1.1 million in funding to help residents go electric. The program was proposed by Gov. Phil Scott and passed by the legislature with the goal to get at least 50,000 EVs on the road by 2025.

The incentives are available to those with an annual household income of $92,000 or less applying for a new PEV with a base price of $40,000 or less, and can be used with additional PEV incentives offered by the state's utilities and federal tax credits.

More: *Saint Albans Register*

VIRGINIA

FERC Upheld on Tx Undergrounding Cost Allocation

FERC was right to exempt Dominion Energy's North Carolina customers from the additional costs that resulted from Virginia officials' decision to require the undergrounding of three transmission projects, the D.C. Circuit Court of Appeals ruled Friday.

Virginia's insistence on undergrounding pushed the price of the Pleasant View, DuPont Fabros and Garrisonville projects from $84 million to $233 million. In upholding the commission's 2014 ruling and its subsequent denial of rehearing requests, the appellate court rejected both procedural and substantive challenges (*EL10-49*). (See *FERC Closes Book on Va. Tx Undergrounding Dispute*.)

The court said the commission was justified in making "a limited exception" to its general policy that utilities do not directly assign individual cost items that are included in projects that have system-wide benefits, citing the absence of any evidence that North Carolina customers caused or benefited from the undergrounding. "Indeed, as the commission recognized, its departure from its policy of having all customers pay for upgrading a grid here maintained consistency with the broader cost-causation principle: Though the benefits of conventional grid enhancement are shared throughout the grid, here Virginians uniquely caused and benefited from the undergrounding."

More: Northern Virginia Electric Cooperative v. FERC (*17-1262*)

WISCONSIN

Regulators Approve Solar Farm, Concerned over Land Use

The Public Service Commission last week approved the 100-MW, 465-acre Point Beach Solar Farm that will be the state's fourth large-scale solar installation authorized in 2019.

The facility will be owned by a subsidiary of NextEra Energy, while the power will be sold to WPPI Energy.

Because of the number of incoming projects, the commission agreed the state will need to address the siting of large-scale renewable energy projects to minimize the impact.

More: *Wisconsin State Journal*

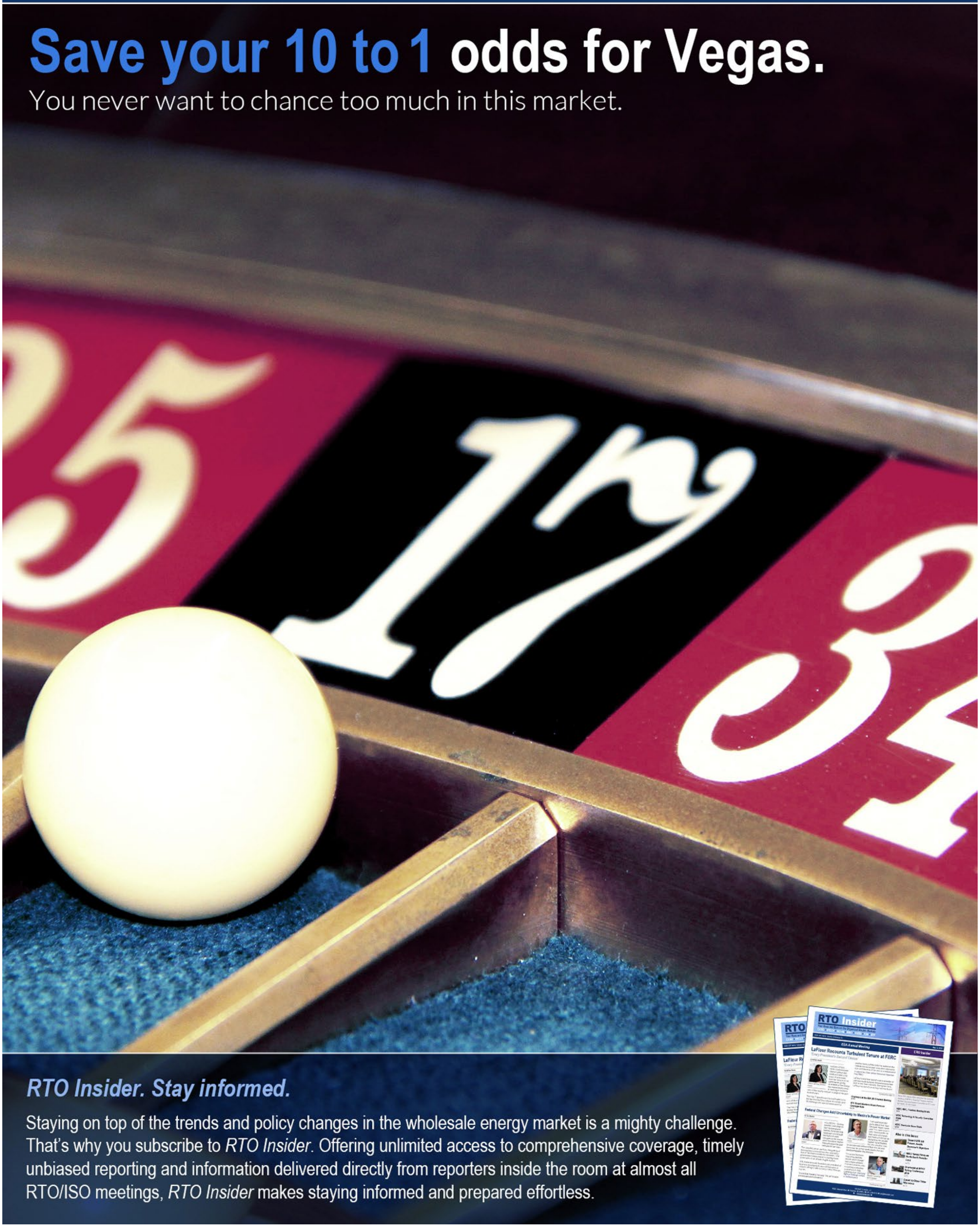
WYOMING

Black Hills Receives Approval for Consolidation, Rate Increase

The Public Service Commission last week approved a settlement agreement for Black Hills Corp.'s natural gas utility, Black Hills Wyoming Gas, for it to establish customer rates and consolidate general tariffs, gas cost adjustments, and certain riders and adjustment clauses.

The new rates will generate roughly $13.3 million in new annual revenue in the hopes of recovering Black Hills Energy's investment in infrastructure and operating expenses. The new revenue is based on a return on equity of 9.4%.

More: *Market Watch*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