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Your Eyes and Ears on the Organized Electric Markets
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Five Questions on Trump's Coal, Nuke Bailout

By Rich Heidorn Jr.

More than a week after President Trump directed Energy Secretary Rick Perry to prevent additional coal and nuclear plant retirements, the administration has provided no additional details on how it plans to implement the bailouts or how much they will cost.

With no answers coming from D.C., analysts and others have been left to speculate on the bailout's potential impact. Here's five important questions and possible answers.

Can the Trump/Perry Plan Survive Legal Challenges?

Trump's directive came after the leak of a 40-page draft Department of Energy memorandum that said coal and nuclear plant retirements are a threat to national security, in part because natural gas pipelines could be subject to terrorist attacks. It called for keeping at-risk plants alive through capacity and energy payments for at least two years while the department studies the risks and then creates a "Strategic Electric Generation Reserve."

The memo cited the Defense Production Act of 1950 (DPA) — enacted to aid the nation's civil defenses and war mobilization at the beginning of the Korean War — and Section 202c of the Federal Power Act, which allows the energy secretary to issue emergency orders during energy shortages.

The DOE memo said the retirements threaten the electric supplies for the

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FERC Blindsided by Half-Baked Trump Order (p.11)

Dems Hit Coal, Nuke Bailout at House Hearing

By Michael Brooks and Rich Heidorn Jr.

DOE's Bruce Walker

WASHINGTON — A senior Department of Energy official told Congress on Thursday his agency has no estimates on the cost of the coal and nuclear power bailout President Trump has ordered, as Democrats blasted the proposal.

Trump directed Energy Secretary Rick Perry on June 1 to force grid operators to provide a lifeline to struggling coal and nuclear plants, saying their retirements threaten national security. Trump's directive came after the leak of a 40-page draft DOE memorandum that cited the Defense Production Act of 1950 and Section 202c of the Federal Power Act, which allows the energy secretary to issue emergency orders during energy shortages.

The memo proposed creation of a "Strategic Electric Generation Reserve (SEGR) to promote the national defense and maximize domestic energy supplies."

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RTO Insider Across North America

RTO Insider reporters fanned across the continent last week for conferences in D.C., Mexico City, Kansas City, Boise and Cape Cod. Clockwise from top left: a panel at the Mid-America Regulatory Conference (p.5); Exelon's Daniel Allegretti at the New England Energy Conference and Exposition (p.9); DOE Undersecretary Mark Menezes at the EIA Energy Conference (p.12); New Energy Update's U.S. Offshore Wind Conference (p.17); FERC Commissioner Richard Glick speaks at the Western Conference of Public Service Commissioners (p.14); and transmission lines in Mexico. The Gulf Coast Power Association held its monthly breakfast in Mexico City (p.3).

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GCPA Mexico City Breakfast

Land Rights Present Unique Challenges to Mexico Tx Developers

By Tom Kleckner

Laguna Verde, Mexico's sole nuclear plant. It is owned by CFE, the state utility. | *nuclear-energy.net*

MEXICO CITY — Bob Smith has enjoyed a long career in transmission planning and development, much of it in the American West where he said federal lands can create "unique problems" for building electric infrastructure.

As vice president of transmission, planning and development for TransCanyon, Smith is responsible for conceptualizing and planning transmission projects for the joint venture between Berkshire Hathaway Energy and Pinnacle West Capital.

BHE is Warren Buffett's energy holding company that includes PacifiCorp and NV Energy. Pinnacle West's assets include Arizona Public Service. Together, they offer $90 billion worth of "leverage" to TransCanyon.

Smith told a Gulf Coast Power Association breakfast audience last week that "there's a clear need for transmission infrastructure" in Mexico, and that the country is "fertile ground for these opportunities."

So why is TransCanyon going to "watch the process and see what happens" for the time being?

Two words, say veterans of the emerging Mexican market: land rights.

"I've gotten the sense it's every bit as difficult here as it is in the United States," Smith said during the June 6 breakfast, the seventh in a series. "I get the sense there's a real value of the long-term commitment to the land and cultural identity."

Stations of the Cross

Just ask Energia Veleta's Mannti Cummins, who is working to develop a 50-MW wind farm in Baja California Sur. He filed a social impact study, one of several necessary requirements before construction can begin, with Mexico's Ministry of Energy (SENER) in July 2016. He received a response back last week.

However, first Cummins had to meet with a SENER representative housed in the ministry's training facility, a dated, one-story, cement building located in a working-class part of Mexico City. Cummins was told his study was in order, but that he would a receive an electronic copy of SENER's "opinion letter" later. The document, indicating the Office of Social Impact Studies had the "necessary and sufficient information" to do its own evaluation, arrived in Cummins' email at 1:10 a.m. He then had to return to the SENER office later that morning to sign a document acknowledging he had received the PDF.

Electronic signatures are not considered official in Mexico, Cummins said.

"They want original, wet signatures. The most mundane business in the U.S. becomes an administrative stations of the cross here in Mexico," said Cummins, a practicing Catholic.

Fortunately for Cummins, the proposed wind farm is in a desolate area of the state, near the oil-fired generators "that keep the beer cold in Cabo." He only had two landowners to deal with, and none of the federal lands, social property, conservation areas and indigenous territory that other developers will face. Still, it took a team of six students working 24/7 for six weeks under their former professor to produce baseline studies, conduct interviews and draft the report.

"It would take anyone else six months," said Cummins, who was facing an investor's deadline. "And this was for 50,000 acres and two landowners."

Legacy of Revolution

Sebastian Robinson, director general of Punto Focal, a surveying firm that specializes in setting real estate boundaries, says 51% of the country now consists of social property called *ejidos*, a result of the Mexican Revolution that dragged on from 1910 to 1940. When you discount the urban areas, he said, that percentage jumps into the 60s.

"The problem is, ownership has become muddled," Robinson said.

Land ownership became an issue in the 1890s, when 20% of the country was owned by foreign interests and rich landowners. By 1910, half the country's rural population worked on huge estates essentially as slaves, and the pent-up frustration was one of the primary causes of the revolution.

It wasn't until socialist Lazaro Cardenas was elected president in 1934 that much of the ensuing violence subsided. Cardenas instituted the practice of *ejidos*, in which peasants within a community were given sub-parcels of former estates or national land — some as large as 120,000 acres — but the land was not necessarily registered, Robinson said. President Carlos Salinas eventually ended the practice in 1992.

Many of the *ejidos'* original owners have long since died without transferring the titles, or they have moved into the cities to escape rural poverty. "With maybe 90% of the *ejidos*, there's no chain of title," Robinson said.

And while the government maintains a public registry of social land, Robinson said there's no legal inventory of land owner-

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GCPA Mexico City Breakfast

Land Rights Present Unique Challenges to Mexico Tx Developers

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ship. The problem is magnified by the lack of accurate surveys.

Robinson and Cummins bring all this up in pointing to the potential difficulties facing the first two competitive transmission projects currently out for bids by Mexico's state-run utility, the Federal Electricity Commission (CFE). Mexico's energy reform of 2014 opened up the transmission system to private contractors, partly because CFE keeps its retail rates artificially low for political purposes, and it can afford to do little more than keep the lights on, Cummins said.

One of the projects is a $1.2 billion, 870-mile, 500-kV connection between Mexicali in Baja California and Hermosillo, Sonora, in northwestern Mexico. The second is the $1.7 billion Oaxaca project, more than 1,000 miles of 500-kV line between Mexico City and Veracruz, home to the country's only nuclear plant. Technical bids on the first line are due Friday, and the Oaxaca bids are due in July, but a requirement of HVDC experience will likely limit the field.

Robinson said CFE already owns 89% of the Oaxaca project's right of way, but that still leaves about 100 miles of line where ownership will have to be determined and dealt with. "That's a lot of problems," he said.

Both projects will be built under a build-operate-transfer (BOT) model, in which private companies will build the infrastructure, operate and maintain the system while recovering rates, and then transfer all the rights, licenses, permits, authorizations and property to CFE.

"CFE used to own it all," Cummins said. "Now, it just administers the network."

Watch and Wait

Still, developers say Mexico is too big of a market to ignore. SENER says the country's generating capacity has doubled to more than 73 GW since 2000, and load growth and the retirement of aging, inefficient plants will require another estimated 50 GW of generation over the next 15 years. Mexico hopes to add $10 billion worth of transmission infrastructure in the coming years, including the two competitive projects.

Smith pointed to Mexico's load growth, broad support for renewable energy and "mature and competent" planning processes as reasons to get involved in the market.

To be fair, Smith said TransCanyon was too late to bid on the Oaxaca project. The company did look at the Hermosillo-Mexicali project, he said, but decided to "monitor progress" of the initial offers "to learn the best way to engage."

"We decided at this point, between the risk and lack of experience [in Mexico], we decided it wasn't a wise thing to do," he said. "We'll try to learn lessons on the best way going forward. There are some tremendous opportunities here. It's early, very early in the process, but it'll be interesting to see how it goes."

Mid-America Regulatory Conference

Overheard

KANSAS CITY, Mo. — Midwestern regulators must not overlook the transformative effects of renewable energy and the pace of advancing grid technologies in their decisions — all while ensuring that electricity rates stay affordable, panelists speaking at a regional regulatory conference advised last week.

Those themes cropped up during several panel discussions at the June 4-6 Mid-America Regulatory Conference. Here's some of what we heard.

Build Large Tx Projects for Wind

Industry experts agreed that new, large-scale transmission is necessary to facilitate a growing influx of wind power, and many said RTOs' current seams processes pose an obstacle.

Nicole Luckey, Invenergy director of regulatory and government affairs, stressed that transmission must be built to unlock the benefits of low-cost wind energy.

RTOs must fix their interregional project processes, Luckey said, pointing out that no major interregional lines have ever been approved between SPP, MISO and PJM.

"Something is clearly going wrong," Luckey said. "Today's transmission planning is reactive rather than proactive."

She added that it's imperative for RTOs to focus on aging and degraded transmission, citing the American Society of Civil Engineers' 2017 Infrastructure Report Card that gave U.S. energy infrastructure an overall grade of D+.

"My company's biggest challenge is not siting interstate transmission lines. Siting is laborious … but it's not the biggest challenge," said ITC Great Plains President Brett Leopold. Instead, the RTOs' differing interregional planning processes can hamper "higher-voltage backbone projects" and leave companies with only "piecemeal lower-voltage reliability projects."

Steve Gaw, consultant for the Wind Coalition and the American Wind Energy Association, agreed that RTO seams represent a stumbling block for building large transmission. "To me, the big hurdle we have today is seams. … We have all this wind generation in the Midwest, but we have these artificial barriers," he said.

Gaw would like to see FERC intervene on the "intensifying" problem of interregional transmission planning. FERC's "interregional piece is so weak that it really hasn't produced anything. I'd like to see FERC weigh back in," he said. "If we don't have somebody applying pressure on this, it's going to continue as it has." He added that he'd like to see a cost study performed on the inefficiencies in deploying resources along the seams.

"I don't think the seams involve a mountain range or an ocean. It's worse — they're political in nature," said ITC Transmission Director of Public Affairs Tom Petersen.

Energy consultant Will Kaul, also chair of the Great Plains Institute, said RTOs have done well in transmission planning. "I think they have a lot to show for it," he said.

But even Kaul wasn't sure if planned transmission buildout by 2030 would be enough to facilitate the renewable energy goals of municipalities and companies. He said insufficient transmission can constrain the full capability of renewable sources.

Nick Wagner, incoming National Association of Regulatory Utility Commissioners president, and co-vice chair of the Iowa Utilities Board, said commissioners in RTO states may "finally be at point where they're tired of" ongoing seams issues. He suggested that regulators may begin initiating meetings with RTO officials and ask for solutions.

Gaw also pointed out that while energy prices continue to decline, the costs to upgrade transmission and distribution are on the rise and need to be properly recovered.

"There is story here that needs to be told. We're moving to a new system," Gaw said.

Russell Feingold, vice president of management consulting at Black & Veatch, said it's time to rethink traditional ratemaking, especially considering low energy demand.

"The problem is that the old regulatory compact does not work in the 21st century," Feingold said. "The traditional volumetric structure, while it served its purpose in the past, perhaps it's not the best practice for recovering utilities' costs."

Feingold said riders like infrastructure trackers can help utilities recover their total cost of service, but he added that it's difficult to arrive at numbers everyone can agree on.

"I often say that if you get five analysts in a room, you'll get five different answers on what costs should be for residential customers," Feingold said.

Trump's Bailout

A few panelists said if President Trump's recent order directing Energy Secretary Rick Perry to prevent further nuclear and coal plant retirements takes effect, it will muddy market signals and infrastructure investment. (See *More Questions than Answers for FERC, RTOs on Bailout*.)

| © RTO Insider

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"The wind industry will not like this," Gaw said of the order.

The fact that coal and nuclear generation are on the brink of retirement demonstrates that the "marketplace is working," Gaw said.

"Cars get old, they get replaced with more efficient models — that's what happening today on the grid," he said. "This approach is going backward and ignoring consumers and market signals."

"The good news is it's easier to keep the status quo than change," Petersen offered grimly, adding a disclaimer that ITC is "agnostic to what the generation source is." Nevertheless, Petersen predicted that the order, if realized, will create "uncertainty and mixed signals" in transmission planning.

"It makes it hard to plan for the future," he said.

Renewables in Demand

General Motors Global Manager of Renewable Energy Rob Threlkeld said his company will achieve 100% renewable energy usage by implementing more energy efficiency measures, addressing erratic renewable generation times through battery storage and influencing public policy.

But Iowa Consumer Advocate Mark Schuling said he had concerns with renewable power purchase agreements when large industrial customers go outside utilities to obtain them, which may leave other customers with higher bills.

"We need to make sure we're not impacting the utility model," he said.

Schuling said utilities should offer environmentally conscious, reliable and affordable energy, appealing to a broad class of customers. He said he often hears residential customers explaining that they can't afford rate hikes because they've been on the "same Social Security income for 20 years."

"There's not a customer comment period where we don't get those type of comments," Schuling said.

He said pilot projects are a good method for testing the effectiveness of new ideas, especially when considering how new energy programs will affect low-income ratepayers.

Nicole Luckey (left) and Lanny Nickell | © *RTO Insider*

"I think storage is the change that's coming that's going to impact generation," Schuling predicted. "We have a lot of wind in Iowa, and when storage comes online, it's going to change" how energy is delivered, he said.

Andy Zellers, Brightergy's vice president of development and general counsel, said the company's current 5-MW solar pilot project with Entergy New Orleans could become a 50-MW project if it tests well. The project still requires approval and is under a non-disclosure agreement, he said.

"I can't say much about [the project], but it's literally on an island. Transmission is bottlenecked getting it in and out of the parish," Zellers said.

Zellers facilitates solar projects for utilities when commercial customers approach them for renewable sources. He said at some point, utilities will have to change their business plans to factor in the green desires of commercial customers.

"Customers with means are coming to the utilities saying, 'We need this,'" Zellers said. "If the utilities are not providing this, they'll go somewhere else."

Zellers said distributed energy-friendly policies can be sold to conservative regulators and politicians if they're marketed using their reliability-enhancing potential and entrepreneurial opportunities.

"These arguments will win eventually," he said, adding it will take "patience and pressure."

David O'Brien, Navigant director of strategy and operations, said the market becomes more contested in nature as distributed energy resources multiply in regulated utilities' territories.

"Increasingly, you can see utilities and third parties competing with one another," O'Brien said.

Sunrun Director of Public Policy **Amy Heart**, whose company focuses exclusively on residential rooftop solar, said she discourages the notion among customers that they'll become independent of the grid after installing solar. Rather, she wants to introduce more diversity into the grid.

But SPP Vice President of Engineering Lanny Nickell said his RTO's 84-GW queue currently contains more renewables than its load can consume. "[SPP] has been called the Saudi Arabia of wind," Nickell said.

Nickell said during one interval in April, approximately 64% of SPP load was served by wind generation.

"If you would have told me 10 years ago that this was doable, I wouldn't have believed it," Nickell said.

If SPP "had the right transmission and the right resources," he said, it could reliably use a generation mix that includes 75% wind generation.

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Electric vehicles could snap up excess wind generation, other panelists pointed out.

"There's a lovely relationship between charging your electric vehicle at night and the surplus of wind energy at night," Luckey agreed.

"We need more EVs. We need more load to be able to absorb all of these renewables," Petersen said.

MISO President and Chief Operating Officer Clair Moeller said his staff talk "about the possibility of a post-capacity world," considering the influx of new non-firm resources.

He noted that MISO is also managing a renewables-heavy queue that — if all projects are realized — will add 93 GW to the its portfolio.

"If we don't solve the queue problem, the solar is going to move to rooftops because the demand is there," Moeller said.

But Luckey said that study delays plague both MISO's and SPP's interconnection queues and can leave new wind projects in a holding pattern.

"Timelines have to be tightened up, studies have to make sense, and studies have to be completed on time," Luckey said.

Steve Kidwell (left) and Rob Threlkeld | © RTO Insider

Rate Design

Samantha Williams, Midwest director of the National Resources Defense Council's Climate and Clean Energy Program, said utilities and regulators should look for ways to encourage DER use in rate design.

"There's an opportunity here to use rate design as an enabler … to get utilities to open opportunities for clean energy for customers," she said.

But she added that rate design should protect low-income vulnerable customers, especially those on fixed incomes.

"Novel and untested rate design should be tested and vetted by credible data," Williams said.

She warned against utilities seeking high fixed charges on utility bills, saying most increase requests are rejected outright or scaled back by state regulators. "Most of the bill should be volumetric."

Williams said she prefers time-of-use rates over mandatory demand charges, adding that residential customers would have to be educated to understand their energy use and pinpoint which household actions cause a high demand charge.

"We're going to have a whole community of people that need education on what triggered the charge. The fact that it's all backward-looking is very challenging as well. I think demand charges are the least understood," Williams said.

"What you can't do is address a demand charge after the fact," Heart said.

Lon Huber, a head of consulting with Strategen, said utilities and regulators should not shake up rates simply to accommodate DERs.

"Rates should avoid rocking the boat for 98% of customers for the sake of 2%," he said. One of the rate designers on Xcel Energy Minnesota's new residential time-

Mark Schuling (left) and Ryan Prescott | © RTO Insider

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of-use program, Huber said he worked to assign an energy cost for every hour of the year. The utility last month won approval from the Minnesota Public Utilities Commission to test a two-year time-of-use pilot program that charges residential customers more for energy consumed during the 3-8 p.m. peak, with the most inexpensive rates occurring at night. The program is set to begin in 2020 for about 10,000 customers.

Huber said utilities developing their own time-of-use programs must make several decisions, including deciding on peak time rebates or a critical baseline rates.

"You're basing a rate design on calling a certain number of critical events per year. If a utility plans for 10, but calls two, does there need to be a rebate?" Huber asked.

Greg Bollom, assistant vice president and regulatory consultant at Madison Gas and Electric, also spoke at the conference. | © RTO Insider

"It gets really tricky really fast."

Ryan Prescott, Tradewind Energy director of market analysis, said that customers choosing not to participate in new energy programs should be shielded from the costs of implementing them.

Prescott pointed to Dominion Energy's recently rejected 100% renewable energy program intended for its large customers as an example of the need for utilities to carefully vet programs.

"Costs weren't very well known," Prescott said of Dominion's program.

"Low-income customers are customers first. They're low-income second," Ameren Vice President of Corporate Planning Steve Kidwell said in a later panel.

Kidwell predicted that Ameren's steady coal retirements will not raise rates, in large part because of inexpensive wind energy coming online. He said it's a "huge opportunity" to be able to keep customer bills low while gradually increasing Ameren's renewable component.

— Amanda Durish Cook

New England Energy Conference and Exposition

Overheard

FALMOUTH, Mass. — New England is up to the task of managing the tough challenges facing its wholesale market and grid — even if there is no grid in the future, regional energy experts said last week.

"The feds are less important now, and New England used to live by its wits — we never had oil or gas — but now we've got offshore wind," **Douglas Foy**, president of energy consultancy Serrafix, said June 4 at the 25th annual New England Energy Conference and Exposition. The event is hosted jointly by the Northeast Energy and Commerce Association and the Connecticut Power and Energy Society.

Looking back on the era of restructuring electricity markets in the 1980s and 90s, "the most significant feature of those times was a collaboration between government, private industry and environmentalists," said Foy, formerly both a secretary of commonwealth development in Massachusetts and president of the Conservation Law Foundation. "There were a bunch of very smart players all trying to get to a common goal."

Political Split

"That's a remarkable thing and quite a contrast to what we see today," said **David O'Connor**, senior vice president for energy and clean technology at ML Strategies. "The way our country is polarized now, it's harder to imagine collaboration."

Fletcher School professor **Barbara Kates-Garnick**, a former Massachusetts undersecretary of energy, said the challenge today is to recreate that collaborative dynamic: "I think it was both trust, collaboration and a recognition of the need to address looming issues that contributed to our willingness to tackle different problems in a collaborative rather than adversarial fashion, as is the mode today."

"Energy efficiency created an environment where now it's so successful, so prevalent, we've levelized the demand that used to be growing inexorably every year," O'Connor said.

Paul McCary, of law firm Murtha Cullina, said the financial incentives of wholesale markets helped form the consensus to try something different, which brought lower-cost power.

"But restructuring the electricity market was not done to face the problems we have today," McCary said, adding that deregulation didn't address the resource mix.

"There are a couple layers to the challenge — the state/federal split, for example," McCary said. "Can you tweak and tweak the market until you get there? I question how many ornaments you can hang on the FERC market-structure tree. The 90s were more simple politically — today is a bigger challenge."

"Screw the feds," Foy said. "I'll always bet on New England."

Laser Grid

Speaking on the second day of the conference, **Peter Kelly-Detwiler** of Northbridge Energy Partners said the industry can thank the Trump administration for bringing resilience to the fore, both with last fall's Notice of Proposed Rulemaking and the president's June 1 order directing the Department of Energy to maintain uneconomic coal and nuclear plants. (See *FERC Blindsided by Half-Baked Trump Order*.)

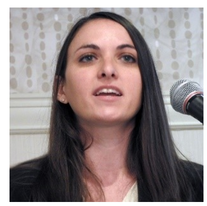
"On climate change, irrespective of one's political beliefs, science is science, and it ain't going away," Kelly-Detwiler said. "I used to think that if I put my hands over my eyes, nobody could see me, but I was 3 when I thought that."

Kelly-Detwiler looked to the future, imagining what the energy space will be in 2050, and said experts are not good at forecasting, as evidenced by looking back to 2001 at anticipated electricity sales, solar penetration or natural gas production.

"Why? Because all our forecasts are based on what we know, not on what we don't know, and on what trends are accelerating and why they're accelerating," he said. "We have to start thinking about what that new dynamic looks like and have that inform our future forecasting."

NASA for several years has been delivering power to an experimental aircraft via laser. "Let's fast-forward to a grid in 2050," he said. "We can send energy to a plane with a laser right now, and we have 32 more years of high-performance computing that's going to accelerate its ability to solve problems for us. One question that would be worth asking is: Do we have a grid at all?"

Shaping Public Policy



"Even if we transition the electric power sector to zero-carbon electricity today, we still would still not be able to meet even the 2030 goals [40% greenhouse gas reduction]," said **Courtney Eichhorst**, lead analyst for regulatory strategy at National Grid. "Clearly the challenge is in two sectors: transportation and heating."

Michael Sloan, managing director of natural gas for energy services company ICF, said public policy should be set with an eye to the future, especially regarding electrification of the residential sector.

"First of all, would residential electrification reduce carbon emissions? It's not clear. What are the impacts on the grid? What are the impacts on consumers, on voters? We've seen policy changes that hurt consumers lead to a change in government in Ontario," he said.

"Policy-driven residential electrification would be a very expensive approach to reducing greenhouse gas emissions," Sloan said. "We should look at the most efficient ways to reduce emissions first, and let the market decide how best to meet residential heating load, at least until the less expensive approaches to reducing GHG emissions

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New England Energy Conference and Exposition

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have been exhausted."

On the issue of eliminating the internal combustion engine and turning to electric vehicles, **Matt Solomon**, transportation program manager for the Northeast States for Coordinated Air Use Management, said "there are so many advantages, so many ways that driving electric is a better experience for the consumer," and people "get it" in one drive.

"States aren't the best communicators ... but Massachusetts is the first state to have actually put money into putting on test-drive events," Solomon said. After an event targeted at high-earning, tech-savvy people, 68% of participants say they are more likely to buy an EV, he said.

On residential distributed energy resources, **Ian Schneider**, a Ph.D. candidate at the Massachusetts Institute of Technology, said that tariff design has to match the grid reality.

"If we don't design the markets correctly, then outdated tariffs will leave this energy revolution to not necessarily benefit all customers," Schneider said.

DERs are disrupting an already outdated rate design, he said. MIT's Energy Initiative identified four obvious inefficiencies with current rate designs: They're neither time-based nor location-based, and "they tend to recover fixed costs volumetrically, so the utility is recovering fixed costs for previous expenses" on a per-kilowatt-hour basis.

As those who can afford solar panels consume less of the utility's power, lower-income people are forced to pay a higher percentage of those fixed costs, which is inherently unfair, he said.

The fourth inefficiency: that the rates don't account for capital investments going forward, "so in a world where the marginal cost of producing electricity is very low, but capacity costs, both for the distribution system and for generation, can be very high, it becomes more important to think about coincident peaks and how consumers are driving peak costs on the system," Schneider said.

New Delivery Model

Daniel Allegretti, Exelon vice president for state government affairs in the East, said there is a continuing tension between the utility and competitive paradigms.

Philip O'Connor, president of energy consultancy PROactive Strategies, said flat load, disruption of traditional generation economics and digital deployment are driving the electricity industry toward a second wave of competitive restructuring.

"We've had a decade in this country in which overall electricity consumption, served by the grid, has not increased," O'Connor said. "The entire business model and the regulatory scheme for the traditional, vertically integrated utility, and for the wires-only company, is predicated on the idea of growth and expansion."

Digital deployment leads to one big thing — customer sovereignty, he said. "Unfortunately, the structure of the industry, especially the vertically integrated part, stymies that development. So what are we left with? We have rising fixed costs, particularly in the monopoly environment, but flat sales, so you've got to keep raising the price."

Brian Conroy, Avangrid director of network projects, said, "We see ourselves as a platform provider, and our collection of projects will deliver the platform and functionality envisioned for a future marketplace and a future grid operating environment."

Public policy for reducing greenhouse gases or increasing the use of renewables usually means starting demonstration projects, he said.

"As we plan the future, everything we do ... for least-cost planning, we have to look at what are the non-traditional alternatives," Conroy said. "We see ourselves as a smart integrator, pulling all these diverse things together with a very smart or intelligent platform ... to squeeze the value out of the distributed energy resources to get the most for our customers."

The smart grid might outsmart the customer, according to Harrison Grubbs, director of strategic partnerships at marketing firm KSV. The firm surveyed people on their attitudes on renewable energy and found that utility customers don't think much about their energy use.

"We wanted to drill down and get an understanding, what exactly customers do know and where those opportunities are," Grubbs said. "We asked customers where does the majority of their electricity come from. Thirty percent said they don't know. We also found that 27% of customers in New England believe that the majority of their electricity comes from coal and oil."

— Michael Kuser

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FERC Blindsided by Half-Baked Trump Order

By Rich Heidorn Jr.

Mark Menezes | *© RTO Insider*

WASHINGTON — FERC was given no advance notice of President Trump's directive ordering Energy Secretary Rick Perry to prevent further nuclear and coal plant retirements and has been provided no details since, officials said last week.

FERC Chairman **Kevin McIntyre** and Department of Energy Undersecretary Mark Menezes had few answers for reporters' questions in brief press conferences after speaking at the Energy Information Administration's 2018 Energy Conference in D.C. last Tuesday morning.

Menezes told reporters DOE is still working out the details of the plan. He said the department would not necessarily be ordering RTOs and ISOs to purchase energy or capacity from at-risk plants — as was detailed in a leaked DOE memo — but that it was one of the options under review.

"We're still evaluating the problem and what the options are," Menezes said. "It was a leaked document that was in the process of being drafted."

He did not respond when asked why Trump had made the directive when the details were uncertain.

McIntyre told reporters that he has not been briefed by DOE nor seen a list of plants that might be affected.

"We had no idea" the directive was coming, an exasperated senior FERC official told *RTO Insider* afterward.

Asked about DOE's contact with FERC, Menezes said, "We talk to FERC on a fairly regular basis. We have not got into any specific proposals with FERC because we're still working on specific proposals.

"This is a process that is bigger than the Department of Energy. ... We're getting input from all of ... the agencies as to how they assess this," he continued — an apparent reference to the National Security Council's Policy Coordinating Committees. FERC is not a principal in the process.

McIntyre said the Trump administration's directive is within the law under Federal Power Act Section 202c.

"The opening phrase uses something along the lines of, 'In a time of continuing war' ... and so it has the feel of a kind of a wartime emergency. It then does go on ... to have more inclusive emergency-type or urgent circumstances-type language that in my view avowedly could be invoked to capture this situation," he said. "That is a decision not for me or anyone at the FERC, but rather for the secretary of energy."

FERC Role in Question

McIntyre said FERC might not be involved in setting prices on rescued generators if they can reach agreements on compensation with RTOs.

"Under [FPA Section 202c] as it's written, and the regulations of the DOE, there are different scenarios that could develop that would not involve a rate proceeding before the FERC. We're looking at those details now as you can imagine."

If FERC is not involved, the contracts would be judged on an "easier standard" than FERC's traditional determinations of "just and reasonable," he said.

McIntyre also discussed Trump's directive in response to audience questions moderated by EIA Administrator Linda Capuano after his speech to the EIA conference.

If the 202c "trigger is pulled" McIntyre said, generating plants could attempt to work out a contract with the entity providing it compensation. "If that effort should fail, then the matter could [come] up to the FERC for what FERC would regard as — for lack of a better term — a rate case ... which the FERC has been handling for decades. So, from that standpoint it wouldn't be a dilemma. In a sense it would almost be bread and butter. We'd have to figure out how to get the dollars and cents right; that would be probably the biggest [challenge]. We've got a very talented staff" to do that.

"If it comes to us as a rate proceeding, it would indeed be subject to [just and reasonable]," McIntyre added in the press scrum later. But a contract negotiated between an RTO and a generator — something [that's] worked out almost in a settlement fashion [is] subject to ... effectively an easier standard ... fair and reasonable," he explained.

Asked whether FERC would have to mitigate the impact of power plant subsidies on the wholesale markets, the chairman responded, "I think there are a number of different ways we could approach it as long as we've satisfied ourselves that it meets our standards of justness and reasonableness."

McIntyre said he didn't know whether the directive would affect the resilience rulemaking FERC opened in January after rejecting Perry's Notice of Proposed Rulemaking to provide cost-of-service payments to coal and nuclear plants with on-site fuel. The NOPR was submitted under Section 403 of the Department of Energy Organization Act. (See *FERC's Independence to be Tested by DOE NOPR*.) In his remarks to reporters earlier, Menezes indicated the policy initiative was far less settled than the memo suggested. He said there is no deadline for DOE's next step.

Asked whether ordering capacity and energy purchases — as spelled out in the memo — was the main option under consideration, he said DOE is considering "as many [options] as people can come up with. ... It's an iterative process."

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EIA Energy Conference

Overheard

WASHINGTON — The headlines at the Energy Information Administration's 2018 Energy Conference were generated backstage, as FERC Chairman Kevin McIntyre and Department of Energy Undersecretary Mark Menezes were questioned by reporters about President Trump's coal and nuclear bailout after their speeches. (See *FERC Blindsided by Half-Baked Trump Order*.)

But an earlier panel featuring officials from PJM, ERCOT and GE Power also provided some highlights. **Stan Kaplan**, director of EIA's Office of Electricity, Renewables and Uranium Statistics, moderated questions from the audience.

Are microgrids a fad?

No, said **Eric Gebhardt,** chief innovation officer for GE Power.

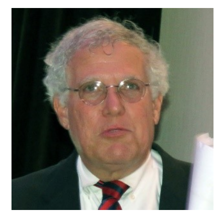
"In many cases, the microgrids are being installed [for industrial uses] because of higher-cost electricity. ... A 10-MW natural gas [reciprocating generator] can produce a [levelized cost of energy] of around 6 cents/kWh, which is extremely competitive."

Adding cogeneration, "a [combined heat and power] application where you take the heat off that to create steam for your process or you use it for HVAC purposes, it drives the value even further. ... With a combined heat and power [application], you could be pushing 90% efficiency in the overall cycle, which is great efficiency.

"The second thing is many customers are looking to decarbonize by putting in solar in conjunction with this. And then you start using energy storage as part of that for peak demand clipping, because many times these microgrids don't [supply] 100% of the load. They might be 80% of the load, might be 70% of the load ... so, there's many ways it can be economic."

In contrast, he said, microgrids "trying to be completely off-grid ... that's not always an economic way to operate today, or not necessarily the most economic way to operate today."

Does a more intelligent, distributed grid increase resilience or make us more vulnerable to cyberattacks?



"Arguably, spreading things out, having distributed resources, microgrids, are in one way maybe increasing the cyber grid [attack surface]," said **Craig Glazer**, vice president of federal government policy for PJM. "You're also enabling [resilience]. It's not like you can attack one substation and take

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FERC Blindsided by Half-Baked Trump Order

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'Not a New Issue'

"This is not a new issue that we've been trying to address. Right?" Menezes continued. "I mean, we sent a [Section] 403 letter over to FERC. ... We've identified this issue for some time. So, we have continued to look at our options."

"Why did the president announce this [June 1] if you don't know what you're doing?" Menezes was asked.

"I didn't say we don't know what we're doing. I said we are considering options, is what we're doing," he responded. "We want to make sure that whatever we do works and is upheld by courts."

The undersecretary dismissed the suggestion that the administration is threatening to disrupt RTO power markets. "FERC has to figure out a way to keep the so-called 'markets' operating. But they are voluntary," he said.

"These markets have not been mandated by Congress. ... It's important for the RTOs to keep their states happy. If the states are not happy with the RTOs in which they participate, the RTOs won't exist. ... These are not natural markets. In fact, electricity is a natural monopoly," he said.

Losing 'Energy Security'

During his address to the EIA conference, Menezes decried the grid's "growing dependence on pipeline-dependent and intermittent resources," noting that there are no mandatory reliability standards for gas pipelines.

He also said the premature closures of nuclear plants has Saudi Arabia and other nations "questioning our commitment to remain leaders in nuclear technology." He said that has opened opportunities for South Korea, which won nuclear generation contracts with the United Arab Emirates, and China, which he said does not require clients to sign the antiproliferation protections the U.S. mandates.

"So, we're losing more than grid resilience. We're losing energy security," he said. "Imagine a world where the U.S. sits on the sidelines while other countries can dictate what other countries can do with their nuclear fuel. Think about that for a few minutes."

EIA Energy Conference

Overheard

Continued from page 12

out metropolitan areas. So, I think on balance [there's] probably more benefit to that."

The bigger challenge, Glazer said, is that there are no mandatory cybersecurity standards for the natural gas pipeline industry, unlike the electric grid.

"You know who regulates the cybersecurity of the natural gas pipeline industry? The TSA [Transportation Security Administration], the people that check your bags at the airport. …

"There is a very small staff. They're dedicated people. But it's a very small staff totally underwater, frankly, in this area.

"If you hit the fuel supply, you're going to have an impact on the electric grid, yet we somehow have just accepted a vastly different structure: voluntary, suggested standards for the pipelines versus mandatory standards for the electric grid."

Are the industry's capabilities keeping pace with the increasingly intelligent, complex grid and the growth of behind-the-meter generation?

"It's a great question that I don't know the answer to," said **Beth Garza**, director of the ERCOT Independent Market Monitor.

"The interaction of more and more data [with] finer granularity, and then having the systems and tools to process this … to turn it into actionable information, I think is a challenge. I tend to be optimistic on all of that … but I do see it as a challenge."

Gebhardt agreed. "How do you deal with going from a thousand centralized power plants to hundreds of thousands and hundreds of millions of end nodes that are going to be producing power, as well as being able to curtail power, simultaneously? How does all of that get managed? That's going to be something that many utilities and technology companies have to deal with."

Glazer recalled the April 2015 power outage that darkened the White House and much of downtown D.C. NERC said it began with the failure of a 230-kV lightning arrester 40 miles south of the capital. (See *Failed Lightning Arrester Caused April Outage*.)

"The outage was not that big a deal, but the restoration was much more complicated because [PJM], as well as the local utility [Pepco], didn't have any visibility into which buildings had backup generation and were running them and which ones didn't.

"So, the [National] Air and Space Museum had backup generation; the Hirshhorn Museum didn't. But nobody knew that. This happened on a patchwork all through Washington. It made the restoration that much more difficult."

California's solar generation has produced the late afternoon duck curve. Why don't we hear about ramping challenges in ERCOT?

"Part of the challenge in California is that customers don't use as much electricity as they do in Texas," Garza said. "It is very much driven by [Texas'] air conditioning load in the summertime. That is supported by solar [generation] but any kind of projection I've done that's grossed up the solar curve on our load curve, I can't get Texas to look like the California duck curve."

Will energy storage replace combustion turbine peaking plants?

"That question comes up a lot," Gebhardt said. "I look at it more as an 'and' versus an 'or' question, because there's so many existing peaking plants that are out there right now. Combining them in a hybrid application with energy storage brings tremendous value. … The batteries handle the really fast ramp rates and allow the gas turbine to come on at a slower ramp rate going from a dead stop. … And if you have it there, it also serves other purposes — voltage support, frequency response…

"Certain parts of the U.S. are testing markets, saying we would take either a combined cycle gas turbine or some sort of gas turbine or energy storage. … But for the vast majority, the 'and' solution is probably the better one."

— Rich Heidorn Jr.

Western Conference of Public Service Commissioners

LaFleur, Glick Promise a Light Touch to Changing West

By Jason Fordney

BOISE, Idaho — Two top federal energy regulators told state utility commissioners that they will take a light-handed approach as the West develops new market structures, allowing flexibility and acknowledging regional differences.

Long-time FERC Commissioner Cheryl LaFleur, and **Richard Glick**, who joined the commission in November, made their remarks to state regulators and industry representatives at the National Association of Regulatory Utility Commissioners' Western Conference of Public Service Commissioners last week.

LaFleur on June 4 noted that dramatic shifts have taken place in the West just this year, with membership changes at Mountain West Transmission Group and competing market proposals from CAISO and Peak Reliability/PJM. (See Multiple Entities, Markets Now Beckon in West.)

"I think the West is the biggest story of 2018, just because of the level of interest and the number of changes," LaFleur said. She told Idaho Public Utilities Commission President Paul Kjellander that she is "trying to send positive vibes out to the West" and "a warm current of support."

She acknowledged that when it comes to federal oversight of the West, the California energy crisis and opposition to FERC's Standard Market Design are still on people's minds. There are also concerns among Western states about increased regulation by FERC during the administration of President Trump.

Cheryl LaFleur and Paul Kjellander | © *RTO Insider*

"Anything that happens cannot be driven from Washington, D.C., because we tried that, and it really failed," she said, adding that "we are trying to not make it a FERC thing — it doesn't really matter what we want."

She said the West "seems to be in a very dynamic place right now." The commission's default answer on Western market integration proposals should be "yes, you can do things differently, unless there is something that is going to be wrong for customers and not just and reasonable."

Appointed in 2010, LaFleur has worked alongside 11 commissioners and is a former chairman and acting chair. Kjellander asked what lessons LaFleur had learned during her time, which last year included a stint as the sole commissioner.

"I definitely have had a very unusual run," LaFleur said. "It's really been a magical mystery tour.

"One my little aphorisms is that life is a movie, not a snapshot," she added. "Things change."

She acknowledged changing political headwinds in the transition from President Barack Obama to Trump. "I really wanted to stay through and come out the other side and be happy, and I have," she said. "I love the work."

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She said that the current FERC membership is still finding its center as a body.

FERC's newest challenge is Trump's June 1 directive to Energy Secretary Rick Perry to prevent further nuclear and coal plant retirements. The announcement was a major topic among attendees at the conference. LaFleur in comments to *RTO Insider* indicated a wait-and-see approach on the directive. (See More Questions than Answers for FERC, RTOs on Bailout.)

Glick Discusses Regionalization, Transmission Incentives

Glick told the conference that when it comes to FERC's regulation of the West, "more of a hands-off approach is best."

He took to the stage on June 5 under emergency lighting, with no microphone or sound system as a local substation problem had the Boise Centre operating with backup generators.

"Obviously, if we just had more coal and nuclear plants, this wouldn't be happening," Glick joked as he opened his speech, drawing laughter from the state officials in the audience. Power was restored during his comments.

Glick noted that when he was at the Department of Energy, he spent a year and a half working "almost exclusively" on the Western Energy Crisis, which he called "an interesting learning experience." He also worked for PacifiCorp, Iberdrola (now Avangrid Renewables) and for Sen. Maria Cantwell (D-Wash.) as counsel to the Senate Energy and Natural Resources Committee.

"We are in an incredibly interesting time in the energy industry right now," Glick said. There have been benefits to the rapid change, he said, including more choices for

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Western Conference of Public Service Commissioners

Pot Industry Blazing a Path in Western Landscape

By Jason Fordney

BOISE, Idaho — The budding efforts to make U.S. marijuana operations more energy efficient will become increasingly critical as the commodity grows into a global market, energy industry experts — including one state utility commissioner — said last week.

"Cannabis is already a $10 billion industry and is becoming a global marketplace," **Derek Smith**, founder and executive director of the Resource Innovation Institute, said June 4 at the annual meeting of the Western Conference of Public Service Commissioners. The Portland, Ore.-based nonprofit works with utilities and growers to improve energy efficiency and develop standards.

With extensive lighting and HVAC requirements, the marijuana industry currently represents about 1% of electricity demand in the U.S. Growing facilities that are not energy efficient can have up to eight times the energy impact of regular buildings.

"The energy impacts are really all over the board, they are broad and they are pretty large. ... It is something to keep track of," Smith said.

Cannabis cultivation is one of the most rapidly changing markets in the world, emerging from the shadows of what was formerly a black market. Growers tend not to trust utilities and the government, he said, as pot is still illegal at the federal level. But a "LEED for weed" certification will eventually be developed, according to Smith.

Marijuana has been legal since 2012 in Washington state, where it is now the third largest agricultural commodity after apples and milk, Utilities and Transportation Commission Chairman **David Danner** said. Sales in the state were $1.4 billion last year, yielding tax revenues of about $312 million.

"It has had quite an impact in our state," Danner said. "It has required our utilities to take a specific interest in it, and for that reason we are interested in it as well." Industry participants have expressed concern about the longevity of pot-growing operations, raising the question of whether utilities could end up investing in assets that will later be abandoned, such as substations or feeder lines.

"What we are seeing now is that these companies are pretty stable," Danner said. "It is going pretty well."

Another concern: that growing and possessing marijuana is still illegal at the federal level, raising the question of whether the operations might be raided and shut down. U.S. Attorney General Jeff Sessions has stated publicly his desire to go after the industry, but so far that has not happened.

State and utility officials have questions about how to extend state energy efficiency programs to marijuana growers in this environment, but many efficiencies could be captured in lighting and HVAC, Danner said. Avista Utilities and Puget Sound Energy have developed incentives and rebates for growers to adopt more efficient lighting, he said. Advanced metering infrastructure will also make it easier to identify illegal growing operations, which still proliferate and use a lot of energy, he said.

"There is also still, in all of your states and mine, an illegal marijuana industry," Danner told fellow commissioners.

At a separate panel discussion, **Linda Gervais**, Avista Utilities senior manager of regulatory policy, said dealing with pot growers was something "we didn't see coming." Even large growers get paid in cash and don't bank in traditional ways because of federal illegality. Large growers can have monthly bills of $30,000 to $40,000, and one grower brought his payment in to the utility's office in plastic garbage bags. The utility has had to buy a cash counter, hire a security guard and hire an armored truck to haul the money.

"It has been a challenge, but I think we have a really good process in place now because we learned how to adapt," Gervais said.

LaFleur, Glick Promise a Light Touch to Changing West

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consumers, lower costs and cleaner energy resources.

"That doesn't mean there aren't some challenges," he said, mentioning integrating renewables and the "duck curve" in California, communities being affected by coal and nuclear plant closures, and difficult issues around Western market regionalization.

He noted that benefits of the Western Energy Imbalance Market are multiplying, the market is growing and "it seems to be working very well." But he added that "I am very aware of the politics *vis-a-vis* FERC and the Western states," mentioning hostility toward Standard Market Design, and lingering mistrust between California and other Western states. Glick said his approach at FERC will be to support regionalization, but "we need to be as deferential as possible."

"If we push the envelope, given the history of FERC and the West, that might not necessarily work out the best for anybody," he said.

Glick also reiterated his call for FERC to review its policy on transmission incentives. "I'm not sure we are really incenting the right thing," he said, noting that FERC routinely grants return on equity bonuses for participation in an RTO or ISO.

"I think the argument is they would be in an RTO or ISO anyhow." He said FERC should be encouraging "right-size" transmission and using existing transmission more efficiently.

Western Conference of Public Service Commissioners

With Big Nukes Dwindling, Supporters Focus on Modular

By Jason Fordney

| © RTO Insider

BOISE, Idaho — With the prospects for large nuclear plants becoming increasingly difficult in the U.S., nuclear proponents last week expressed excitement about the future of small modular reactors, touting their flexibility and lower capital cost.

Small modular units offer the clean benefits of nuclear while being more easily tailored to varying usage and sites, and the technology is seeing significant federal investment and partnership, industry experts told the annual meeting of Western Conference of Public Service Commissioners. During a panel discussion, they noted that other countries such as China and Russia are pursuing nuclear while it is being driven out of markets in the U.S.

Moderator Stan Wise, former chairman of the Georgia Public Service Commission, noted that the panel didn't include any opposing viewpoints as is often the case at similar events. He said the discussion was "informational" and not about whether nuclear should — or should not — be pursued.

Wise stepped down as chairman of the state commission in February, maintaining his support for the continuing expansion of the controversial Vogtle nuclear plant — a stance for which he was "unapologetic," he told the audience. (See *Georgia PSC Votes to Complete Vogtle Units*.)

"I think we need to be aware of opportunities for changes, for enhancements and for a new paradigm," Wise said.

The current nuclear fleet is a "24/7" baseload resource that provides about 60% of non-greenhouse gas-emitting generation in the U.S., said Doug Little, who left the Arizona Corporation Commission last year to join the Department of Energy as deputy assistant secretary for intergovernmental and external affairs. Portions of Little's comments echoed the Trump administration's conclusion that nuclear units, along with coal plants, contribute to national security, the subject of a controversial order issued by the president last week. (See *More Questions than Answers for FERC, RTOs on Bailout*.)

"The department has been very supportive of this technology," Little said. "We don't want to see the industry move offshore in terms of the technology and the knowledge base." He pointed to the benefits of small nuclear because of its modular nature and flexibility in siting.

Little used the analogy of a Ford F-150 pickup truck and a Prius hybrid electric vehicle. While the large utility vehicle might have a high operating cost and be less environmentally efficient than a compact EV, "I can do things with that F-150 that I can't do with a Prius," such as hauling a large load of hay on a farm. There are national security benefits of baseload plants, he argued, as 98% of military facilities get power from utilities and gas supply disruptions and price spikes can occur.

"How do we properly value these assets?" Instead of focusing strictly on price, the reliability value of nuclear should be considered, Little said. "I think the conversation needs to be broadened a bit, and that is what we're trying to do at the department."

Economic factors have shut down six reactors in the U.S. since 2013, with 12 more planned to go offline by 2025, said Rita Baranwal, director of the Idaho National Laboratory's Gateway for Accelerated Innovation in Nuclear (GAIN) program. There are only two reactors under construction in the U.S., but there are 18 being built in China with another 31 planned, and five under construction in Russia with 22 more planned, she noted in a presentation. There are currently 440 operating reactors in 30 countries and 50 under construction in 13 countries around the world, she said.

Rita Baranwal and Stan Wise | © RTO Insider

"We want to ensure we have the continuing operation of the existing [U.S.] fleet," Baranwal said.

Jose Reyes, chief technology officer of Oregon-based NuScale Power, described the giddy growth arc of the company founded in 2007. The Nuclear Regulatory Commission accepted the design application for its small modular reactor for review in March 2017, seen as a breakthrough regulatory hurdle for the technology. About $720 million has been invested in the technology, including $226 million from DOE in a competitive funding opportunity and a $40 million DOE matching fund award this month.

The NuScale Power Module can be stacked in up to 12 units for 600 MW in gross output. Its first deployment, a 12-module plant at a Utah Associated Municipal Power Systems site, is due for 2026 commercial operation.

"It's exciting for me to see how this small dream has gotten this far," Reyes said. "I wake up in the mornings and I pinch myself."

New Energy Update's U.S. Offshore Wind Conference

Competition, Cooperation and Costs the Talk at OSW Conference

By Michael Kuser

BOSTON — Competition among states to set the highest offshore wind energy targets and to secure supply chain jobs is gradually giving way to a regional cooperation, the head of the Bureau of Ocean Energy Management said last week.

"In our view, all of the federal leases, they don't belong to any particular state, and we need to be thinking about how to manage those assets on a regional community basis," acting BOEM Director **Walter Cruickshank** said at New Energy Update's U.S. Offshore Wind Conference, held June 7-8.

"And we're certainly seeing that already," Cruickshank added. "We've seen projects that were leased off of one state getting agreements with neighboring states."

He cited the collaborative development efforts of Massachusetts and Rhode Island, of "Virginia and the Carolinas, and obviously in the New York Bight, where there are a lot of states that have stakeholder interest."

In May, Vineyard Wind, a partnership between Avangrid Renewables and Copenhagen Infrastructure Partners, won a contract to supply Massachusetts with 800 MW of offshore wind energy. In the same solicitation, Rhode Island picked Deepwater Wind to build a 400-MW version of its Revolution Wind proposal. (See *Mass., R.I. Pick 1,200 MW in Offshore Wind Bids*.)

Picking up the Pace

Panelists at the conference also discussed ways to reduce costs and speed up permitting.

The Department of Energy's 2015 Wind Vision report set a goal of deploying 86 GW of offshore wind by 2050. The U.S. would need to use about 4.2% of the total technical resource area to reach the goal, according to the National Renewable Energy Laboratory's September 2016 Offshore Wind Energy Resource Assessment. The technical resource area includes areas of the Great Lakes and the Atlantic and Pacific coasts with wind speeds of at least 7 meters/second and water depths of less than 60 meters (Great Lakes) or 1,000 meters (the oceans).

The 11 BOEM leases issued so far could produce 20 GW by 2030 "based on the physical capacity of these leases," said Tom Harries of Bloomberg New Energy Finance. The typical timeline from lease to operation is five to seven years.

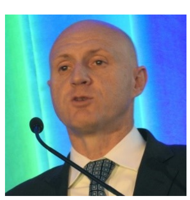
Stephen Bull, senior vice president at Norway-based Equinor (formerly Statoil), said he'd like "to see BOEM interact more at the state level, to really try to fast-track or work quicker to get wind energy areas out there." Conference chair **Stephen Pike**, CEO of the Massachusetts Clean Energy Center, a state agency in charge of offshore wind development, asked about having BOEM pre-permit the leases to speed up development, as is done in Europe.

"That's not the way the federal government works," said Cruickshank, explaining that the bureau has no funding for capital-intensive marine surveys.

Floating Turbines

Although BOEM's leases to date have been off the Atlantic Coast, BOEM is also looking to the Pacific, which will require floating wind technology because of the much greater water depths, Cruickshank said.

"We're cautiously optimistic we'll be able to move ahead with some of those leases later this year."



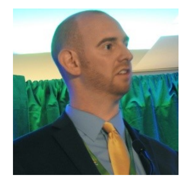
Daniel Simmons, principal deputy assistant secretary for DOE's Office of Energy Efficiency and Renewable Energy, said improving floating platforms "is an important area for us just because so much of our wind resources offshore is in deep water."

Walter Musial, manager of offshore wind at the National Renewable Energy Laboratory, who explored the levelized cost of energy for floating turbines, said about 58% of potential offshore wind areas are deeper than 60 meters.

"Floating obviously starts out a bit more expensive, but it's a maturity thing, so fixed and floating turbine costs converge over time," Musial said. "Actual costs are confidential — they don't report them in the newspaper."

Manufacturers need to see the market demand in order to develop optimized turbine systems for floating platforms, he said. "Up till now, every single deployment has been with a turbine that was actually designed for a fixed bottom system, so we're sub-optimum," he said.

But the industry is now moving beyond the floating prototype phase. "I've counted about 11 projects totaling 229 MW," Musial said. "These are going in with some subsidies, but also with regular financing, and they're going in all over the world."



NREL wind analyst **Garrett Barter** agreed, saying the current design paradigm of offshore turbines "won't give you a cost-competitive floating system."

Engineering and design are just a fraction of the total cost for a floating wind turbine. Most of the costs are the operational expenses, logistics, assembly and installation, and financing, he said.

"So you really need a systems approach that can tackle all these complexities at the same time, and not just focus on the turbine itself," Barter said. He recommended multidisciplinary analysis and optimization, which is "a tool and also a state of mind where you connect the whole power production process, the whole load path, the controls that sit in between those two, and the whole balance sheet over the lifecycle of the plant."

He said the offshore industry may have to evolve into a structure like that of the aerospace industry, where a global supply chain serves a system owned by the prime contractor.

Driving Down Costs

Experts say it will take several years for the

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Competition, Cooperation and Costs the Talk at OSW Conference

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U.S. market to mature before it matches the separate cost curves for the established European market

"We think the transition happens around 3 to 4 GW of installed capacity, which should be in 2028 in the U.S., and the industry will move onto the established cost curve and really see price reductions," Harries said. "The regulatory route gets simplified, and then gradually you build your experience and you move down this cost curve. Supply chains gain experience, and routes to market become very clear."

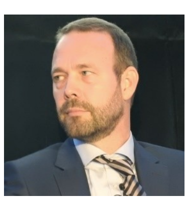
Jonathan Cole, managing director of offshore for Avangrid parent Iberdrola's renewable business, wants to see nearly that much capacity entering the pipeline each year.

"As soon as possible, get to a place where this market is being fed with 2 to 3 GW of new projects every year, which means you've got enough volume to support a local supply chain," Cole said. "That's when you'll truly see cost reductions and the industrialization happening."

Cole said that so far, they've been able to lower development costs through tax credits, which are now being phased out.

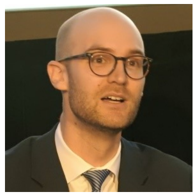
"We're hoping that the downside of removing the tax credits is going to be more than compensated by the positive ... making a more efficient and optimized installation," he said.

Northeast Advantage



Vineyard Wind CEO **Lars Thaaning Pedersen** said tax credits are an important part of the price structure in Massachusetts, but "the benefits ... these projects will bring to the southeast coast" of New England may be more important, such as avoiding the high cost of building transmission lines to bring hydropower from Canada.

The state "has taken a bold step already ... and I'm confident that Massachusetts will be at the center of the industry," Pedersen said.

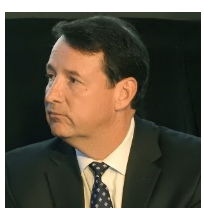


Francis Slingsby, head of strategic partnerships at Orsted, congratulated Pedersen. Despite not winning the first round of the Massachusetts-Rhode Island solicitation, Slingsby said Orsted is committed to developing its Massachusetts lease areas, "which in our estimation are superb."

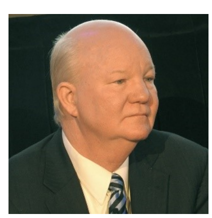
"Wind speeds increase as you move farther north along the coast, which gives New England an innate advantage," he added.

Massachusetts Energy Secretary **Matthew Beaton** referred to the previous day's tour of the New Bedford Marine Commerce Terminal, which was built for the deployment of offshore wind, as evidence of the state's chance to lead the industry.

"To see international companies come in with Massachusetts companies made me realize ... this thing's for real, this thing's happening, and we have all the pieces that we need," Beaton said. "Eight hundred megawatts is just the starting point."



Bill White, MassCEC director of offshore wind development, said, "Growth in Massachusetts is really about ... what it will cost to ratepayers."



John B. Lavelle, head of offshore wind for GE Renewable Energy, said volume will be the biggest driver of cost reductions. Lavelle said GE will "compete in the U.S. with our 12-MW platform that we just announced."

Operating costs will come down partially through "a lot of automation," Lavelle said. "You don't want to send people 15 miles off the coast if you don't have to."

NY, NJ, Md. Moving Forward

Elisabeth Treseder, senior regulatory adviser for Orsted, said New Jersey's commitment in May to build 3,500 MW of offshore wind by 2030 — surpassing New York's target of 2,400 MW — "provides a lot of certainty and reassurance" to the market. (See Gov. Signs NJ Nuke Subsidy, Renewables Bills.)

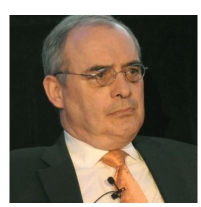
"We're still waiting for the New Jersey Board of Public Utilities to finish its plan, which for us means focusing on the local supply chain and workforce development," Treseder said. "New Jersey was very wise in passing a $100 million tax break for offshore wind manufacturing, which left them an additional pool [of incentives] for suppliers."

Kenneth J. Sheehan, director of economic development and emerging technologies at the BPU, said the state is working to develop its master plan and its first solicitation.

"We are looking for suppliers, transmission, for all the factors that go into it, and the OREC [offshore wind renewable energy credit], the single price, up-front method of funding, takes all this into consideration," Sheehan said.

Jim Lanard, CEO of Magellan Wind, asked Sheehan what his state's position is regarding wind energy areas that could serve both New York and New Jersey.

"Half the New York Bight is in New Jersey, so we're not practically upset about additional project development off our shore," Sheehan said, referring to the Atlantic Coast region between Cape May, N.J., and Montauk Point on Long Island. "At the start, it's every state for itself. ... Everything could be supplied from New Jersey. And New York thinks the same of itself."



Kevin Knobloch, president of transmission developer Anbaric's New York Ocean Grid, said that particularly with New Jersey's goal of 3,500 MW, there's a sense of great urgency to get the first turbines in the water.

Continued on page 19

New Energy Update's U.S. Offshore Wind Conference

Competition, Cooperation and Costs the Talk at OSW Conference

Continued from page 18

"We believe the wise approach is from the very first solicitations to separate generation from transmission, and open it up to competition," Knobloch said. "In so doing, the state decision-makers still reserve the right to go with an offer that's bidding on both attributes."

Doreen Harris, director of large-scale renewables at the New York State Energy Research and Development Authority, said the agency is also identifying new wind energy areas off New York City. There is a proceeding before state regulators now "to make the first utility-scale procurement later this year," she said.

Christer Geijerstam, director of the Empire Wind project for Equinor, which bought the first New York lease in 2016, said that aside from preparing for a state bid, the company is "focused on project technical issues to reduce asset risks" prior to the hoped-for start of construction.

John Hartnett, business opportunity manager of U.S. offshore wind for Shell Wind Energy, said his company "had really jumped into the U.S. markets driven by the evidence of the northeast. Right now, we are investigating the upcoming lease opportunities, both in Massachusetts and New York, and are very hopeful to have site control in time to participate in the upcoming auctions."

The Maryland Public Service Commission approved two offshore wind projects totaling 368 MW in May 2017, allowing the developers to receive ORECs. The projects are estimated to create 9,700 full time equivalent jobs and result in more than $2 billion of economic activity in Maryland, including $120 million of investments in port infrastructure and steel fabrication facilities.

Left to right: Christer Geijerstam; John Hartnett; and Doreen Harris. | *© RTO Insider*

Samuel Beirne, wind energy program manager for the Maryland Energy Administration, said that "most offshore wind developers have to contract through the state Public Service Commission [to obtain ORECs] ... and most use a third-party consultant to help them."

Aileen Kenney, senior vice president of development for Deepwater Wind, said the company's 120-MW Skipjack project off Maryland will start construction in 2021 and go online the following year.

"Right now we're mapping all the seafloor, doing bathymetry analysis," Kenney said.

Production Tax Credit

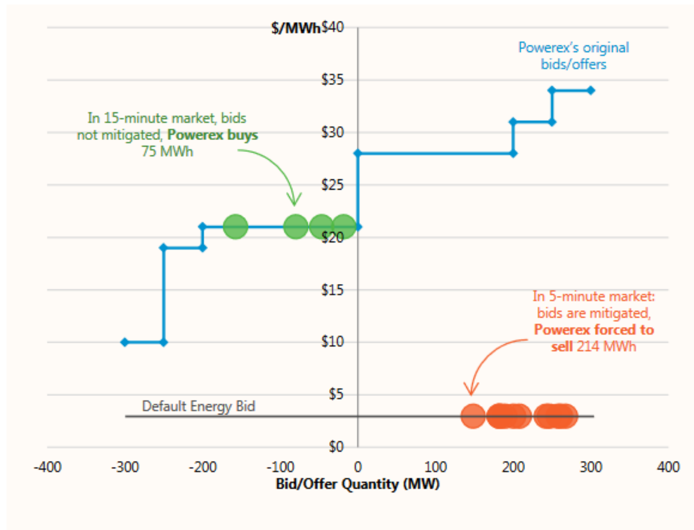
According to DOE, the federal renewable electricity production tax credit is an inflation-adjusted 1.9 cent/kWh tax credit for wind for the 2017 calendar year. The credit lasts 10 years after the date the facility is placed in service.

The tax credit is phased down for wind facilities as a percentage reduction: for wind facilities beginning construction in 2017, the PTC amount is reduced by 20%; for 2018, 40%; and for 2019, 60%.

CAISO News

Troubled Waters for Powerex in Western EIM

By Robert Mullin



| Powerex

PORTLAND, Ore. — Two months after making a smooth integration into the Western Energy Imbalance Market, Canada-based Powerex now finds itself navigating a turbulent relationship with market rules the company says undercut the value of its hydroelectric resources, company officials said last week.

At issue for Powerex is the frequency with which transmission constraints at the U.S.-Canada border trigger CAISO's local market power mitigation (LMPM) process in the EIM, which mandates use of default energy bids (DEBs) to settle transactions. Inflexibility in the formulas underpinning the DEBs often leave Powerex market operations out of the money, the company says.

"The LMPM processes and the DEB options are not workable for Powerex or for external hydro more generally," Powerex Director of Power Jeff Spires said during a presentation at a June 6 meeting of the EIM Regional Issues Forum meeting at Bonneville Power Administration offices.

Powerex, which markets surplus power for the government-owned BC Hydro utility, began transacting in the EIM on April 4. As part of its membership, Powerex has volunteered about 300 MW of its transfer capacity into the market, half of which links British Columbia with the Puget Sound Energy balancing authority area (BAA) near Seattle. The other half allows transfers into CAISO via the Malin delivery point on the California-Oregon Intertie.

"We participate with large-scale hydro that's very fast-ramping," Mike Goodenough, Powerex trading manager, told the forum. "Often times we're in a 'buy' mode, and particularly when the market is in oversupply, we're buying, and the transmission can become constrained because we ramp so fast during the market power mitigation market run [that] the ties fill. And at that point, there's a constraint and market power [mitigation] kicks in. The default bids then kick in and override all of our bids and offers."

The problem in those instances, Goodenough said, is that the EIM's DEB options are "more or less formulaic" and "often very wrong" with respect to Powerex's opportunity costs during a trading interval.

The result is "very frequent mitigation" that forces Powerex to sell below its opportunity costs when it intends to be purchasing in the market to take advantage of arbitrage, Goodenough said.

During these periods, Powerex's traders seek to raise their sell offers upward to avoid sales but are prevented from doing so when mitigation kicks in, defaulting the market to rely on DEBs.

"And because the default bids are wrong, where we would be a buyer, we are now in the dispatch run as a seller," he said. "And so, there's obviously two problems there. One is, we're now selling into a market in which there might already be in oversupply. But more importantly for us, we're now depleting energy-limited resources at the wrong time."

In an April 30 presentation to a CAISO workshop on broader DEB issues, Powerex described the shortcomings of each default bid option available to EIM market participants heavily reliant on hydro assets:

- The "variable cost" option, based on heat rates, fuel price and greenhouse gas costs, is "not relevant" for hydro resources that are more driven by opportunity costs than variable production costs.
- The "backward-looking" LMP option — based on the on the lowest 25th percentile of LMPs at which a resource has been dispatched during the previous 90 days — is "not workable" for hydro resources whose opportunity costs "are driven by current and expected future conditions."
- The "negotiated rate" option, in which a formula is negotiated between a resource's scheduling coordinator and CAISO and its Department of Market Monitoring, is "theoretically workable" for all resources but "not workable in practice" for hydro resources outside the CAISO BAA. This option requires the ability to determine a methodology to estimate expected marginal costs, "which are complex, dynamic, and involve both objective and subjective factors," Powerex said.

"You can't precisely estimate costs for hydro," Spires told the forum. "External [to the CAISO BAA] hydro in particular has multiple bilateral opportunities. We have a myriad of constraints within the BC network," including seasonal monthly, weekly and daily storage requirements, as well as recreational constraints.

"There's so many different things and they can change at the drop of a hat and you need to be able to respond to that, and so we really support flexibility in determining what your marginal opportunity costs are," Spires said. He said the flexibility is

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CAISO NEWS

Troubled Waters for Powerex in Western EIM

Continued from page 20

required to avoid "forced sales."

Spires said that the EIM's LMPM process functions as if the supplier conduct threshold for triggering mitigation is zero, meaning that "as soon as your bid or offer price is even a penny above the reference price, then you're subject to potential mitigation if the transmission is constrained."

"It goes beyond the commercial impact — it's an operation impact as well," Spires said. "And it's a loss of control of being able to decide what to do with your resources in light of the information that you have at the time."

Unlike other EIM members, Powerex functions only as a marketing operation and not as a balancing authority or load-serving entity, which means it has no ratepayers exposed to EIM prices.

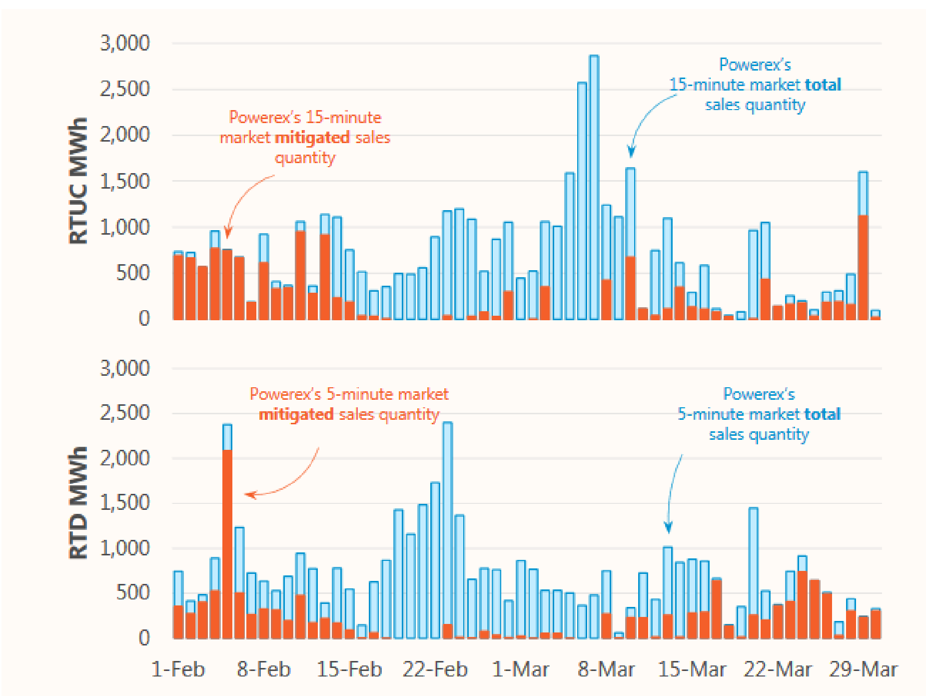
Thus, the company says its import transfer path into British Columbia is used primarily for "economic displacement" (importing low-priced power to displace use of internal generation) and doesn't serve any retail customers. In its April 30 presentation, the company questioned whether it was appropriate to apply LMPM to transfer paths where "there is no potential for market power."

Spires said the situation is discouraging Powerex's participation in the EIM.

"It's frankly less attractive than the existing real-time market — the intertie bidding framework where we don't face these issues, [and] particularly for us, because we have transmission access to the CAISO and so we've got the opportunity to deliver a clean supply into that market," he said. "And so the EIM is a step backwards from that perspective."

Spires concluded his presentation by expressing appreciation for CAISO's support in transitioning Powerex into the EIM, but he also urged the ISO to address the company's dilemma soon.

"We think that it is important to others, and we're looking forward to working on these issues, but we need a resolution quickly."



| *Powerex*

Interim Solution?

In April, CAISO asked FERC to approve a Tariff waiver to alleviate the impact of LMPM on Powerex's operations by reducing the number of intervals for which mitigation applies after being triggered (ER13-1889).

"The interim solution consists of an automated process by which Powerex's EIM transfers will be restricted only during intervals in which this condition [producing forced sales] occurs, as well as limiting mitigation of Powerex's aggregated participating resource to the market interval in which the mitigation of that resource is triggered," CAISO said in its filing.

The ISO said the interim solution "will apply solely to Powerex's aggregated participating resource operating under the unique Canadian EIM entity arrangements."

But while the potential Tariff waiver would partially alleviate the LMPM issue for Powerex, the company has noted it would not address the company's underlying concerns about the DEB calculation options or the fact that its sales prices would be mitigated to uneconomic levels when LMPM is triggered.

During the April 30 workshop, CAISO Vice President for Market Quality and Renewable Integration Mark Rothleder acknowledged "there is a gap" between what some stakeholders "feel their ultimate opportunity costs are and what they believe a calculated DEB under the existing mechanisms can achieve."

"This may be the fundamental issue in terms of continuing the EIM and the success of the EIM, so we have to get this right," Rothleder said, adding that the ISO must receive comments from stakeholders before kicking off an initiative to address the DEB issue.

While time might be of the essence for Powerex, CAISO told *RTO Insider* on Monday that "no time frame has been set for this miscellaneous stakeholder process as of this time, although we do plan to have a second workshop in July to further discuss the concerns and some ideas for addressing them."

ISO-NE NEWS

ISO-NE Begins Real-time Dispatch of Demand Response

By Michael Kuser

ISO-NE said last week it has become the first U.S. grid operator to put demand response into its energy dispatch along with generating resources.

The RTO's price-responsive demand (PRD) structure, which took effect June 1, enables full integration of DR into its energy, reserves and capacity markets.

Like generators, active DR is now eligible to submit day-ahead and real-time energy offers and receive wholesale market payments for energy, operating reserves and capacity. DR resources can be co-optimized in the RTO's economic dispatch, committed by the RTO a day ahead and dispatched in real time.

"The new thing is that active demand response resources can participate by submitting price and amount offers in the day-ahead and real-time energy markets, and they can set price," said ISO-NE spokeswoman Marcia Blomberg.

Modest Impact

Blomberg said the impact of the changes on the markets has been modest thus far.

"On several hours on several days, we've seen small amounts [of DR] clearing," she said of the RTO's experience since the beginning of the month. "On other days, no DR cleared."

Active DR resources are dispatchable because they can reduce consumption at will by reducing industrial production or switching to on-site generators or storage. Passive DR — energy efficiency and distributed solar generation, for example — are not dispatchable.

Active DR was previously able to offer load reductions at a price in the day-ahead energy market, but their offers were administratively evaluated after the market had cleared. DR offers were not used to determine the optimal dispatch of resources or to set price.

Both active and passive DR have been able to participate in the capacity market since 2006. Participating DR was dispatched only during grid emergencies, Blomberg said.

RTO/ISO	2013 Potential Peak Reduction (MW)	2013 Percent of Peak Demand [8]	2014 Potential Peak Reduction (MW)	2014 Percent of Peak Demand [8]
California ISO (CAISO)	2,180 [1]	4.8%	2,316 [9]	5.1%
Electric Reliability Council of Texas (ERCOT)	1,950 [2]	2.9%	2,100 [10]	3.2%
ISO New England, Inc. (ISO-NE)	2,100 [3]	7.7%	2,487 [11]	10.2%
Midcontinent Independent System Operator (MISO)	9,797 [4]	10.2%	10,356 [12]	9.0%
New York Independent System Operator (NYISO)	1,307 [5]	3.8%	1,211 [13]	4.1%
PJM Interconnection, LLC (PJM)	9,901 [6]	6.3%	10,416 [14]	7.4%
Southwest Power Pool, Inc. (SPP)	1,563 [7]	3.5%	48 [15]	0.1%
Total ISO/RTO	**28,798**	**6.1%**	**28,934**	**6.2%**

Potential peak reduction from U.S. ISO and RTO DR programs | *FERC*

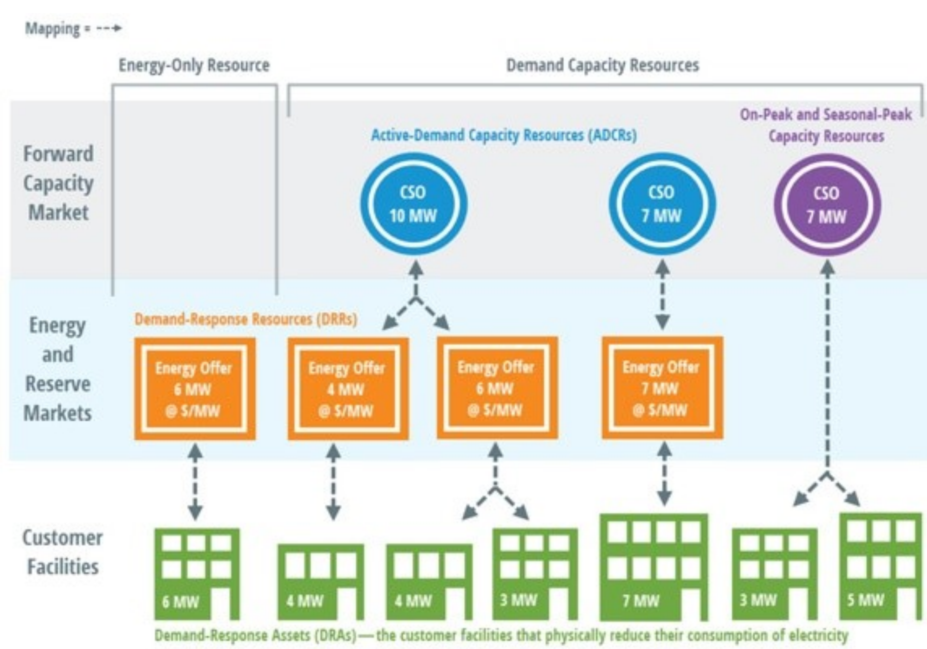
In March 2011, FERC Order 745 required RTOs/ISOs to pay active demand resources the market price for helping to balance real-time supply and demand.

'Enormous Project'

Integrating active DR into the markets "has been an enormous project, requiring the ISO to not only develop and implement extensive market rule changes, but to update computer systems and processes related to grid operations and market settlement," Henry Yoshimura, director of demand resource strategy, explained in the RTO's newsletter. "Consequently, the full integration of active demand resources was achieved in a staged approach."

Facilities that reduce their consumption of electricity are known as demand response assets (DRAs). DRAs under 5 MW can be mapped to a DR resource that participates in the energy and reserve markets. A DRA that is 5 MW or larger must participate individually as its own resource.

DR resources can be mapped to an active demand capacity resource (ADCR) for participation in the capacity market. Passive DR resources may only participate in the capacity market.

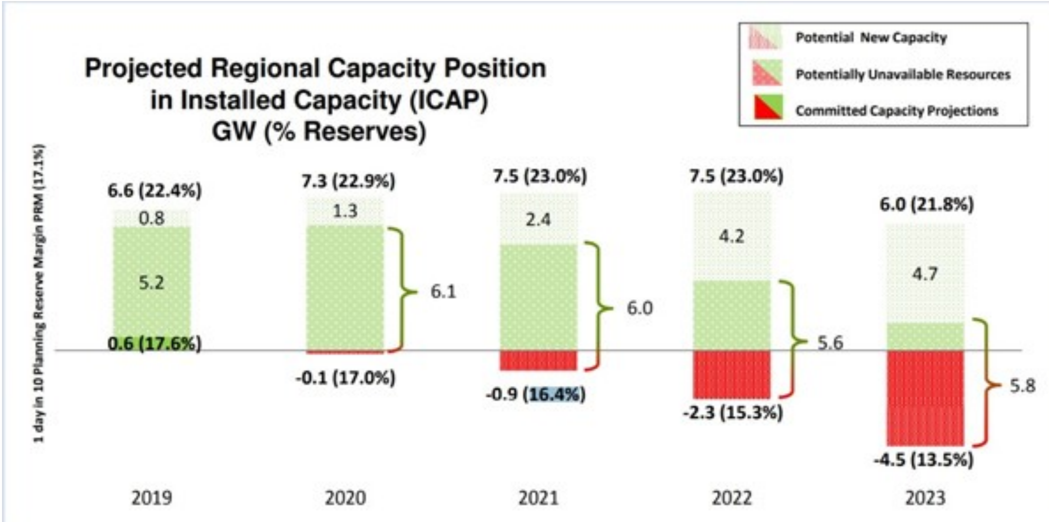


Demand response participation in ISO-NE markets | *ISO-NE*

MISO NEWS

OMS-MISO Survey Reveals Dimmer View of Future Supply

By Amanda Durish Cook



| MISO

CARMEL, Ind. — MISO's supply picture for the next five years is less rosy — and less clear — than it was a year ago, according to an annual capacity survey released Friday in conjunction with the Organization of MISO States.

This year's OMS-MISO resource adequacy survey projects that the RTO's 2019 spare capacity will exceed its regional requirement by anywhere from 0.6 to 6.6 GW, yielding a reserve margin ranging from 17.6 to 22.4%.

But survey results show the volume of spare supply after next year is less certain, owing to expected decreases in resource commitments, although it's still possible the RTO's excess capacity could outpace the high end of its 2019 prediction through 2022. Using the current 17.1% planning reserve margin, over the next five years, MISO's footprint could see anything from a 7.5-GW surplus to a 4.5-GW shortfall:

- In 2020, MISO could have anywhere from a 7.3-GW surplus (representing a 22.9% planning reserve margin) to a 0.1-GW shortfall (a 17% reserve margin).
- In 2021, the RTO could experience anywhere from a 7.5-GW surplus (23%) to a 0.9 shortfall (16.4%).
- In 2022, the chance of a shortfall increases, with a range between a 7.5-GW surplus (23%) and a 2.3-GW shortfall (15.3%).
- In 2023, MISO's possible high-end capacity surplus drops to 6 GW (21.8%), while the possible shortfall could reach 4.5 GW (13.5%).

Last year's survey showed MISO would have anywhere from 2.7 to 4.8 GW of excess resources from 2018 to 2022, translating into a 16 to 22% reserve margin because of lower demand forecasts and a lukewarm growth rate of 0.5%, down from 0.8% in 2016. (See *Capacity Survey Shows MISO in the Black*.) In this year's five-year outlook, the regional growth rate again decreased from 0.5% to 0.3%. MISO said 97% of load responded to the survey.

"While we continue to see decreasing demand in the MISO footprint, the story continues to be the evolving generation portfolio," MISO CEO John Bear said in a statement. "As the MISO footprint continues to transform, we must learn to adapt in areas such as our transmission planning studies, market-based solutions that focus on speed and flexibility and enhancing coordination with our neighboring seams partners."

During a June 8 conference call to discuss results, MISO Executive Director of Resource Planning Patrick Brown acknowledged that this year's survey shows more risk to resource adequacy than projected last year.

"The main driver of this resource adequacy risk are generation retirements," Brown said, adding that more retirement announcements have occurred since MISO and OMS collaborated on the 2017 survey, resulting in about 4.6 GW of decreased resource availability. The RTO said the majority of potential deficits are concentrated in Illinois' Zone 4 and Michigan's Zone 7. Brown noted the resource adequacy risk is higher because the RTO predicts it will require higher future reserve margins because of its increasing forced outage rate.

But Brown also pointed out that the survey represents a "snapshot," and that more capacity than currently expected could come online to offset retiring generation.

"MISO fully expects this forecast to change going forward," he said.

Zones with surplus capacity can help neighboring zones with capacity deficits, Brown added.

"Zones with deficits do not automatically face a reliability risk," he said.

But by 2023, zones enjoying surpluses may not be sufficient to entirely cover possible capacity deficits in three zones. By that year, the survey showed Zone 4 could face either a 1.1-GW capacity surplus or a 2.8-GW capacity shortfall, while Zone 6 in Indiana and Kentucky could experience anywhere from a 0.3-GW surplus to a 1.6-GW shortfall. Zone 7 faces the most certain shortfall, ranging between 0.8 and 1.8 GW.

Brown said MISO's current 93-GW interconnection queue contains 80 GW of renewable energy, with just 580 MW of storage in the works to make renewable capacity more dependable. However, he said, MISO fully expects more storage to enter the queue in

Continued on page 24

MISO News

FERC Seeks Info on MISO South Plan, SPP Tx Limit

By Amanda Durish Cook

FERC is seeking more specifics on MISO's plan to improve its procurement of reserves in MISO South, asking the RTO in a June 5 deficiency letter how it will impact the contractual transfer limit on flows crossing SPP transmission (ER18-1464).

MISO proposed in late April to apply its existing reserve procurement enhancements — first rolled out in 2011 in MISO Midwest — to the sub-regional constraint between Midwest and South.

The RTO's reserve procurement enhancement models the effects of transmission constraints by accounting for the deliverability of reserves deployed from market-cleared resources and adding a marginal cost of delivering reserves to the zonal reserve market clearing price. The change would also subject sub-regional capacity commitments in South and binding flows in the Midwest-to-South direction on the sub-regional limit to the Independent Market Monitor's mitigation authority.

MISO's reserve procurement practices currently only apply to physical transmission constraints, not contractual constraints like the sub-regional limit with SPP.

MISO acknowledged in its filing that a new product providing capacity within 30 minutes would be most effective in solving South's lack of fast-start resources and reserve scarcity but said its April proposal was a more near-term solution and asked that it become effective June 27. The RTO said it currently makes out-of-market commitments to meet South capacity requirements that result in high revenue sufficiency guarantee (RSG) costs.

In stakeholder meetings, MISO staff have said that a short-term capacity reserve would be especially helpful in South, which has less than 500 MW of capacity available within 30 minutes. The West of the Atchafalaya Basin load pocket has 100 MW of 30-minute reserves, while Amite South has none. (See "Short-term Capacity Product is a Go, MISO Concludes," *MISO Market Subcommittee Briefs: April 12, 2018*.)

In an affidavit accompanying the filing and supporting expanded mitigation, Monitor David Patton said that South is more susceptible to market power than Midwest because South has more pivotal suppliers.

But FERC said MISO's reserve plan only promised to abide by "appropriate limits" of its sub-regional transmission and did not explicitly reference the maximum contractual limits set forth in the MISO-SPP transmission use settlement agreement struck in 2015. The commission said it was "unclear" if MISO intended to abide by the established megawatt limits in the proposal. The commission also asked MISO to explain its generation shift factors — especially when the MISO-SPP contract path binds on flows into South — and to explain its process for updating shift factors.

FERC issued the deficiency letter after regulators from Texas, Arkansas, Louisiana, Mississippi and New Orleans filed a limited protest May 24. The regulators asked that MISO specify that its reserves procurement modeling will use a 3,000-MW limit on north-south flows and 2,500-MW cap on south-north flows, reflecting the regional directional transfer limits in the MISO-SPP joint operating agreement settlement.

The commission required MISO to list the number of hours by month that the sub-regional constraint bound in each direction during 2016 and 2017. It also instructed MISO to estimate the amount of RSG payments that would be affected had the changes been active in 2016. MISO had said that its proposal to extend mitigation would reduce RSG payments.

Finally, FERC asked MISO whether it or Patton could produce "any studies or analyses regarding the expected increase in the frequency with which the ... constraint will bind into MISO South once MISO applies the reserve procurement enhancement provisions."

The commission gave MISO three weeks to respond to its questions.

OMS-MISO Survey Reveals Dimmer View of Future Supply

Continued from page 23

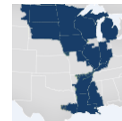
the future.

"It's particularly import that we're doing this in light of the evolving resource mix," OMS Executive Director Tanya Paslawski said of the survey.

This year's survey relied on a new calculation for estimating the volume of future new resources. MISO tallied projects not yet in the three-part definitive planning phase (DPP) of its interconnection queue (and those having entered the DPP's first phase) at a 10% completion rate. Conventional and intermittent resources in phase two of the DPP were counted at 50% and 25%, respectively, which increased to 75% and 50% in phase 3. Projects still negotiating a generator interconnection agreement were tallied at 90% completion, while those with signed agreements were counted as new generation in the survey's weighted averages. (See *MISO RASC Briefs: Little Change to Capacity Forecasts*.)

MISO staff will present a more detailed rundown of OMS-MISO survey results at the RTO's July 11 Resource Adequacy Subcommittee meeting.

MISO NEWS



MISO Stakeholders to Rank Market Improvement Ideas

By Amanda Durish Cook

CARMEL, Ind. — Over the next month, MISO stakeholders will rank 14 market improvements the RTO might undertake in 2019.

Stakeholders have until July 12 to take MISO's Market Roadmap candidate ranking survey and organize eight new and six existing improvements by priority. The survey was announced during a June 7 workshop.

In addition to ranking the eight new submissions approved this spring for consideration by the Steering Committee, stakeholders will also consider six currently active initiatives that have already been discussed in stakeholder meetings. (See *Steering Committee Advances MISO Market Improvement Ideas*.)

The active items under consideration include:

- Improving generator modeling so it can depict more combinations of combined cycle units;
- Creating a short-term capacity reserve product available to solve capacity shortages within 30 minutes;

Mia Adams | © *RTO Insider*

- Developing a multiday market forecast;
- Improving storage resource integration beyond what is required for FERC compliance;
- Automating dynamic ratings for transmission lines that offer temperature-adjusted and short-term emergency ratings; and
- Continuing to develop new market rules and requirements under MISO's large resource availability and need effort. (See *MISO Looks to Address Changing Resource Availability*.)

MISO will review survey results at the August Market Subcommittee meeting, and then reconcile its preferred ranking with stakeholders' prioritization to update a work plan for 2019 to 2023, said Lakisha Johnson, the RTO's market strategy adviser.

The RTO has already issued a first draft of the roadmap based on internal rankings of the 14 proposals, designating its resource availability and need (RAN) effort, and plan to create a short-term capacity product as top priorities, followed by better modeling of combined cycle generators. Next on the list: creating a look-ahead dispatch tool, improved modeling of all generators and more comprehensive storage resource integration. The RTO ranked all other candidates as low importance.

This year's ranking features only a partial list of roadmap ideas and doesn't include improvements relegated to the "parking lot," the lowest-ranked candidates that MISO and stakeholders predict will be useful sometime in the future. Parking lot items are reintroduced in the ranking for refreshed status every other year.

"Each year, we alternate between doing a fully exhaustive ranking of the parking lot versus only focusing on active and new candidates," explained MISO Senior Manager of Market Strategy Mia Adams.

However, this year, MISO moved the

Continued on page 26

MISO News

FERC Rejects Stay of Presque Isle SSR Surcharges

By Amanda Durish Cook

FERC last week rejected a request for a stay of its approval of MISO's refund report related to a system support resource on Michigan's Upper Peninsula.

The Michigan Public Service Commission joined with multiple load-serving entities in the state to request a stay of the surcharges associated with MISO's 2017 refund report, arguing that a FERC-ordered reallocation of the SSR costs for the Presque Isle coal plant amounted to retroactive ratemaking.

But FERC determined that the requestors "will not suffer irreparable harm absent a stay" of the reallocation of costs to cover the unprofitable but necessary operation of the plant in 2014 and 2015 (ER14-2952-005).

The PSC and many of the same LSEs are also party to an ongoing D.C. Circuit Court of Appeals case challenging FERC's 2015 order directing MISO to reallocate SSR costs to LSEs that required the SSR for reliability, instead of to all LSEs in the American Transmission Co. pricing zone on a *pro*

Presque Isle power plant

rata basis. The groups argue the reallocation requires Upper Peninsula ratepayers to cover a disproportionate 98% share of the SSR costs, which Wisconsin ratepayers should help defray. (See *Michigan Groups Contest Presque Isle Cost Allocation*.) MISO's 2017 surcharge report includes cost reductions from a FERC-ordered $24.6 million refund, after the commission decided Presque Isle owner Wisconsin Electric Power Co. overcharged ratepayers for the two SSR agreements.

The Michigan groups contended that, absent a stay, the refund process would become too complex, especially if FERC's reallocation order is reversed. They also said relocation of customers complicates the refund process.

"It would be impossible to ensure that the surcharges imposed by MISO are billed to the retail customers who received service during the surcharge period in 2014, and it would be impossible to ensure that any future refunds received by load-serving entities from MISO are credited to the same customers who paid the surcharges," they said.

But FERC said overseeing the surcharges after reallocation and refund, while challenging, is not impossible. The commission also said the parties' "irreparable harm" argument does not hold up, as corrective relief could be ordered by the D.C. Circuit.

"The difficulties alleged by the Michigan parties are typical of the challenges that jurisdictional entities must overcome to implement the commission's remedial actions," FERC said. "Nothing the Michigan parties have argued has shown that issuing a stay is required by the public interest."

FERC also said the Michigan parties could not prove the surcharges amounted to retroactive rate increases, noting the commission has "broad equitable discretion in determining whether and how to apply remedies in any particular case."

MISO Stakeholders to Rank Market Improvement Ideas

Continued from page 25

suggestion for financial incentives for primary frequency response from the parking lot into the Market Roadmap because Indianapolis Power & Light submitted a new version of the suggestion.

Some stakeholders wondered if some improvements should be combined with others.

"There's some concern if you make something of a Frankenstein roadmap product," Adams said, adding that MISO may be open to bundling market improvements into portfolios when it makes sense.

Customized Energy Solutions' Ted Kuhn said he thought the roadmap was meant for more in-depth market improvements than some of the new ones submitted this year, singling out Independent Market Monitor David Patton's new recommendation to remove transmission charges from coordinated transmission service with PJM.

Patton said the coordinated transactions with PJM are rarely used, and the product has "failed" because MISO levies charges when an offer is made in addition to when an offer is struck.

But Kuhn said the Monitor's suggestion could be completed "in a weekend" and questioned its consideration in the roadmap.

MISO Executive Director of Market Operations Jeff Bladen said Market Roadmap items represent "a variety of dimensions" and said stakeholders should come with suggestions on which products could be fast-tracked.

Northern Indiana Public Service Co.'s Bill SeDoris said one parking lot item should be considered sooner than next year — creating a compensation process for energy delivered during a system restoration event, an idea currently on hold. The item is timely and fits well into current discussions around resilience, SeDoris said. He added that the issue had been discussed recently in closed session discussions of the Reliable Operations Working Group.

Patton cautioned against focusing too much on the resilience "buzz word" when deciding which improvements to undertake.

SeDoris responded that MISO might appear remiss for not having discussed restoration energy compensation the next time it goes before FERC to discuss resilience. He said he would bring the issue to the Steering Committee's next meeting in the hopes of reigniting interest in creating a compensation mechanism.

MISO NEWS

MISO Offers Straw Storage Proposal to Meet Order 841

By Rich Heidorn Jr.

Electric storage resources (ESRs) 100 kW or larger would be eligible to offer capacity, energy and ancillary services under a straw proposal MISO officials presented to stakeholders Wednesday.

FERC Order 841 (RM16-23), which requires RTOs to remove barriers to storage's participation, includes 74 requirements, which MISO broke into eight categories. (See *FERC Rules to Boost Storage Role in Markets*.)

The Market Subcommittee will take the lead on six of the issues:

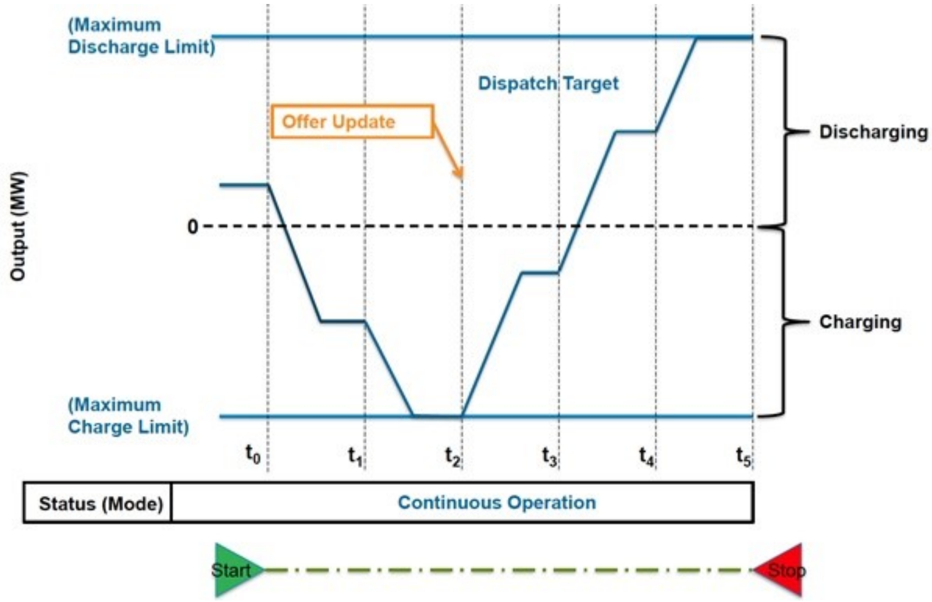
- definition, elements and modeling, including minimum size requirements;
- market participation (bid parameters, offers, commitment and dispatch);
- state of charge measurement and management;
- market participation (eligibility, as seller and buyer);
- metering and accounting; and
- settlements (make-whole payments, compensation, performance and penalties).

The Reliability Subcommittee will address reliability (qualification) and non-market products. The Resource Adequacy Subcommittee will focus on capacity and resource adequacy administration.

MISO officials outlined the proposal during a daylong joint meeting of the three subcommittees and the Planning Advisory Committee.

The RTO expects stakeholder discussions through October and completion of the plan for a compliance filing on Dec. 3. Implementation would begin in December 2019. The first resources registered under the new participation model will be able to participate starting March 1, 2020.

In meeting Order 841's requirements, MISO's compliance filing will also address shortcomings FERC identified in the RTO's existing Tariff rules on Stored Energy Resources (SER) – Type II. MISO previously proposed the SER – Type II category in response to FERC's partial granting of Indianapolis Power and Light's earlier complaint on its storage rules. (See *FERC OKs MISO Plan to Expand Storage*.)



Continuous operation mode | *MISO*

Four Commitment Modes

The new rules will apply to batteries, flywheels, compressed air, pumped hydro and any other technologies meeting FERC's definition of an ESR: one "capable of receiving electric energy from the grid and storing it for later injection … to the grid."

Resources could be connected to the interstate transmission grid, a distribution system or behind the meter. Demand response, which cannot inject energy, is excluded. The initial ESR participation model also will not accommodate distributed energy resource aggregations across multiple pricing nodes.

The RTO said it will expand the ESR category in the future based on improvements to its Market Systems, the Market Roadmap and advances in storage technologies.

ESRs would participate under four modes of commitment: charging, discharging, continuous operations and outage/offline, as specified by the market participant for individual dispatch periods. When in online mode, storage will be treated as must-run resources.

The state of charge will be managed by the market participant and communicated to MISO via telemetry and offer parameters.

A storage resource would pay the LMP of their commercial pricing node when withdrawing charging energy and receive payment at the LMP during injections. Storage will be eligible for make-whole payments under MISO dispatch decisions consistent with eligibility rules for other resource types.

In addition to providing energy, capacity and ramping, storage will be permitted to offer non-market-based services (reactive supply and voltage control and black start).

Rehearing Request

On March 19, MISO asked FERC to clarify or change some aspects of the order. For example, it requested a phased approach for small ESRs (less than 5 MW). It suggested up to 50 be permitted in the first year and 150 in the second.

It also requested a six-month extension for implementation relating to issues pending in the commission's separate DER proceeding (RM18-9, AD18-10).

MISO asked for feedback on the straw proposal, including responses to a questionnaire by June 22. The proposal is expected to be discussed at the RASC on July 11 and MSC on July 12. The proposal is also expected to be mentioned at the Energy Storage Task Force meeting on June 27.

NYISO NEWS

NYISO Favors Cost Levelizing on Carbon Charge

By Michael Kuser

Row	Parameter	Equation	Load	Suppliers
[1]	Energy (MWh; + is gen)		-100	100
[2]	LBMP, incl. carbon ($/MWh)		$35	$35
[3]	Energy bill ($; + is a payment)	[1] * [2]	-$3,500	+$3,500
[4]	CO2 emissions to serve load (tons)		n/a	25
[5]	CO2 price ($/ton)		n/a	$50
[6]	Residual to load & CO2 charge to gens ($)	[4] * [5]	$1,250	-$1,250
[7]	Net energy rate ($/MWh)	([3] + [6]) / [1]	$22.50	$22.50
[8]	Net energy bill ($)	[3] + [6]	-$1,250	+$2,250

How carbon residuals occur | *NYISO*

RENSSELAER, N.Y. — NYISO continues to propose a cost-levelizing approach for allocating carbon charge residuals to load-serving entities, it told New York's Integrating Public Policy Task Force (IPPTF) and stakeholders last week.

The ISO's preferred approach would have suppliers embed the carbon charges into their all-in day-ahead and real-time energy offers, as they currently do with emissions costs under the Regional Greenhouse Gas Initiative, as it presented to the task force in April. (See *NY Task Force Briefed on Carbon Charge Mechanics*.)

The June 4 allocation discussions were part of issue Track 2 in the group's five-track effort to price carbon emissions into New York's wholesale electricity market.

Progress Review

IPPTF Chair Nicole Bouchez, the ISO's principal economist, reviewed the task force's progress in meeting almost weekly every Monday over the past eight months. She said the group is on track to deliver by December either a proposal to incorporate the cost of carbon into the wholesale market, provide a detailed schedule to complete the proposal next year or notify the task force if it concludes that the plan is not viable.

A draft proposal is slated to be delivered Aug. 1, Bouchez said.

"It is absolutely critical that we move quickly to get to a point of either this is going to happen or this is not," said Mark Younger of Hudson Energy Economics. "We need clarity on that as soon as possible so that if it's not going to happen, we can proceed with other things that will."

Couch White attorney Kevin Lang, representing New York City, asked why stakeholders needed to move quickly.

"Because we have a serious problem with a substantial mismatch between public policy actions and our markets, and it is causing severe damage in our markets," Younger said.

"No, that's your view that there's a mismatch," Lang said. "The [Public Service Commission] is adhering to its public policy, which it has every legal right to do. You may not like the result, but that doesn't mean we need to move very quickly on this issue, which is not yet fully developed."

Fair Cost Burden

Locational-based marginal prices would increase according to the emissions rate of the marginal, price-setting resources — the marginal emissions rate (MER).

"As a result of load paying the full LBMP for their energy withdrawals, and suppliers not receiving the full LBMP for their energy generation — them being charged for their carbon emissions — there is an imbalance between bills and credits," said ISO staffer Nathaniel Gilbraith. "This imbalance is what we're calling a residual, and it's going to be returned to loads using one of the methods we discuss today."

The ISO's presentation last week detailed three approaches to allocation of residuals: load ratio share, cost levelizing and proportional allocation, with the latter two based on the carbon effect on each zone's LBMPs.

The load ratio share results in all LSEs receiving the same refunds on a dollar-per-megawatt-hour basis, causing greater differences in the net cost of carbon pricing. On the plus side, it would provide LSEs with price signals more reflective of the carbon intensity of their consumption.

Cost levelizing produces the most similar cost burden in terms of dollars per megawatt-hour of carbon charge, but it also limits the differential price signal to reduce consumption, Gilbraith said. Zones with high MERs would not necessarily see an incentive to reduce consumption relative to those with lower rates.

Proportional allocation would return carbon charge residuals to all LSEs based on the proportional effect carbon prices have on their gross energy payments. It would return more revenues to LSEs facing higher dollar-per-megawatt-hour cost impacts but would not go as far as levelization.

The ISO said this provides some balance between economic efficiency and equity of cost burden by maintaining some of the differential price signals to encourage reduced consumption and emissions.

Continued on page 29

NYISO News

NYISO Favors Cost Levelizing on Carbon Charge

Continued from page 28

In its 2025 base case analysis, the ISO said downstate LSEs would face the highest net increase in energy payments (carbon payments minus residuals) under the load ratio share (8.93 cents/kWh) and the lowest under levelizing (8.96 cents/kWh).

The impact on upstate would be reversed: 6.57 cents/kWh under load ratio and 6.71 cents/kWh for levelizing.

Gilbraith added that the analysis did not cover allocation by LSEs to retail customers, which would be under PSC jurisdiction.

Lang said he understood not considering retail allocation but noted that the ISO assumed that a carbon charge would affect the price of renewable energy credits, which is entirely under PSC jurisdiction. "So why are you picking and choosing which area of PSC jurisdiction you're going to intrude into and which parts you're not?" he said.

Michael DeSocio, the ISO's senior manager for market design, said the ISO is working "to make sure that if a market-based carbon pricing effort like this would move forward, that future determination of RECs and other products like that could be adjusted to consider that alternative. ... We're filing comments [with the PSC] regarding ORECs [offshore wind RECs] on how a contract structure could work with a carbon pricing mechanism [to] minimize any double compensation."

Topics for discussion include whether residuals allocated to an LSE should be allowed to exceed that entity's gross carbon payments and what criteria stakeholders are looking for in terms of equity vs. cost burden.

Status, Schedules

The ISO in May began running the task force, which it set up last year in partnership with the state's Department of Public Service.

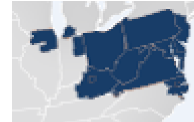
The straw proposal assigned to issue Track 1 was delivered on April 30 and reviewed by stakeholders May 14, and therefore will be closed, said Bouchez.

Track 2 focuses on the market mechanics of a carbon charge and has so far had the broadest range of topics covered of any track, Bouchez said. The IPPTF will discuss the track on June 18 and July 9, and the schedule has five open Mondays through October in case the group needs more time on it.

Track 3 covers how a carbon charge should be set and adjusted for the Track 5 customer impacts analysis. No additional work has been scheduled on Track 3 since DPS staff and a stakeholder both presented recommendations for setting the carbon charge, which is ultimately the responsibility of the PSC.

Track 4 focuses on a carbon charge's interactions with other state policies and programs, and there is no additional work currently scheduled. The group plans one more meeting on Track 5 customer impacts analysis before starting the base modeling work. The group will also meet to review assumptions used in the "dynamic change case" analysis, with stakeholder review in September and October, Bouchez said.

The task force next meets June 18 at NYISO headquarters to address Track 5 assumptions and scenarios on customer impacts, and wholesale market processes under Track 2.



Court Backs FERC Reversal on PJM Tx Upgrade

By Rich Heidorn Jr.

The D.C. Circuit Court of Appeals on Friday backed FERC in its revised interpretation of a PJM Tariff provision governing responsibility for transmission upgrades, turning aside a challenge by the owner of a power plant in Marcus Hook, Pa. (*ESI Energy v. FERC*, 16-1342).

At issue was whether LS Power Associates, the parent of West Deptford Energy, should be liable for transmission upgrades ordered before the developer entered PJM's interconnection queue. In 2014, the court vacated FERC's order ruling the company was liable, calling the commission's decision "the very essence of unreasoned and arbitrary decision-making." (See *Appeals Court Scolds FERC over West Deptford Interconnection Dispute*.)

West Deptford submitted its interconnection request on July 31, 2006, and was later informed it would be assessed $10 million for improvements PJM ordered as a result of two previous projects, FPL Energy Marcus Hook and Liberty Electric.

Tariff Change

Under section 37.7 of the PJM Tariff then in effect, the RTO could seek reimbursement for a previously constructed network upgrade if the new proposed project used the added capacity created by the project or would have required it itself. The reimbursement request only applied if the cost of the upgrade was at least $10 million and it was placed in service no more than five years before the interconnection customer's queue closing date.

If section 37.7 controlled, West Deptford would have been required to reimburse Marcus Hook and Liberty Electric for the upgrade. (Ninety percent of the upgrade's cost had initially been assigned to Marcus Hook.)

In 2008, however, while West Deptford's interconnection request was pending, PJM won approval for an amendment changing the assignment of responsibility for prior upgrades. Section 219 of the revised Tariff allowed PJM to seek reimbursement for previously constructed upgrades for only five years "from the execution date of the interconnection service agreement for the project that initially necessitated" the upgrade.

FERC initially ruled that West Deptford must pay, concluding that the 2006 rules applied. But the court said FERC's ruling "provided no reasoned explanation for how its decision comports with statutory direction, prior agency practice or the purposes of the filed rate doctrine."

FERC Reversal

In response to the remand, FERC in August 2016 reversed its ruling, relieving West Deptford of the reimbursement obligation (ER11-4073). FERC said it based its decision on the "significant skepticism" the D.C. Circuit expressed in the remand order and the "numerous shortcomings" the court identified in the commission's analysis.

Marcus Hook appealed, saying the old rules should apply to West Deptford and challenging FERC's interpretation of the five-year trigger under the new rules. (Florida Power & Light subsidiary ESI Energy was later substituted for Marcus Hook as petitioner.)

In siding with FERC, the court said the commission "directly and adequately addressed" Marcus Hook's challenges to the determination that section 219 applied.

FERC was required to provide a "reasoned explanation" of how applying section 219 comported with the Federal Power Act and commission precedent, the court noted. "Unlike its prior decision, the commission's decision on remand did both," it said.

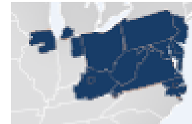
5-Year Trigger

Although section 219 did not specify what action was required within the five-year window to trigger cost responsibility, FERC said the most reasonable interpretation was that the "end date" was that on which West Deptford signed its interconnection agreement.

Marcus Hook argued that section 219 made an interconnection customer liable for an upgrade that entered service during the five years preceding the customer's queue entry. It said the dispositive date should be either when West Deptford submitted its interconnection request (July 31, 2006) or when PJM determined that the upgrade was required for its interconnection (November 2006).

"Although Marcus Hook's suggested interpretation is a possible reading of the Tariff provision, it is no more reasonable than the one the commission put forward," the court ruled. "Accordingly, we find that the commission did not err in its interpretation of section 219 of the revised Tariff."

West Deptford Energy power plant construction | *MJ Energy*



FERC: AEP Must Divulge Plant Data to PJM Monitor

By Robert Mullin

American Electric Power must provide PJM's Independent Market Monitor with requested cost data for a gas-fired plant the company owns in West Virginia, FERC ruled last week (EL17-22).

In October 2016, the Monitor asked AEP to furnish the variable operations and maintenance (VOM) cost data the company used to develop its Sept. 1, 2016, cost-based offer for the 505-MW Ceredo generating station. The Monitor said it was seeking the data to determine whether the level of the cost inputs for the plant raised market power concerns in PJM's energy markets.

Attachment M of PJM's Tariff authorizes the Monitor to "review upon its own initiative at any time" the incremental costs included in a generator's offer price cap to ensure the seller is complying with the RTO's cost development guidelines. The Tariff also permits the Monitor to "make reasonable requests" for additional cost information from a seller after providing "an explanation of the need for the information and the [Monitor's] inability to acquire the information from alternate sources."

Attachment M also stipulates the Monitor can initiate legal or regulatory proceedings to compel disclosure, including petitioning FERC, if requested information is not provided within a reasonable amount of time. The Monitor filed its petition in November 2016.

AEP asked FERC to dismiss the Monitor's petition, arguing it "is not about the exercise of market power or any violation of a Tariff provision or market rule" but instead focused on the Ceredo plant's VOM calculation, which was then subject to a broader pending dispute before the commission regarding day-ahead offers that vary by hour (ER16-372, *et al.*).

Rather than probing market power concerns, AEP contended, the Monitor is really seeking to impose a VOM standard that differs from PJM's current rules. The company noted the Monitor and PJM have taken opposing positions related to the appropriate calculation of VOM costs in the hourly offers docket. If the Monitor wishes to pursue changes to the calculation, it should pursue the FERC-approved process set out in Attachment M, the company argued.

But the Monitor "should not be permitted to make an example of AEP for purposes of advancing its agenda to impose the 'short run marginal cost' standard," the company said.

AEP also argued the Monitor's request for information was not reasonable given it had neither identified a potential market rule violation nor alleged the company had exercised market power. Furthermore, the burden of producing the request information outweighed any benefit, and the IMM's effort is an impermissible audit, the company said.

Drift

In its comments to FERC, PJM largely sided with AEP's position, contending that the Monitor is seeking to compel AEP to provide data supporting the exact type of costs the Monitor has called into question in the hourly offers docket. The ongoing conflict stemming from that proceeding prompted PJM to initiate a stakeholder process over the issue.

"To the extent the IMM would seek to refer AEP to the commission Office of Enforcement while the very matter itself is being contested before the commission on a generic basis, issues could arise as to the relationship of such referrals to the commission's formal process, pursuant to [Federal Power Act] sections 205 and 206, to take comments on and ultimately rule on proposed tariff submittals based on a formal written record," PJM said.

Ceredo Generating Station | *AEP*

The RTO urged FERC to "provide guidance" on whether the Monitor's request is reasonable "both in type and scope" to avoid future disputes and assure market participants "that the IMM's authority to make requests for information is not boundless."

The RTO also asked the commission to require the Monitor "to explain how the information it seeks relates to concerns other than the disagreement it has with how the PJM rules regard short-run marginal costs, adding it has concerns that the Monitor could "drift" into auditing market participants.

Commission Decision

But FERC's ruling came down solidly in favor of the Monitor, noting that it has "broad authority" to review cost inputs and incremental costs and that its request for Cerredo's total VOM costs — including identification of costs by category — was reasonable.

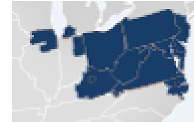
The commission also dismissed the concerns of both AEP and PJM regarding the potential conflict with the parallel hourly offers proceeding.

"The pendency of a PJM stakeholder process to clarify certain aspects of the PJM rules governing cost-based offers does not render unreasonable this specific request for cost data. The IMM retains its ongoing authority and responsibility set forth in Attachment M to review sell offers, cost inputs and incremental costs," the commission said.

"In response to concerns that the IMM may be seeking to impose a cost standard that is inconsistent with the PJM Tariff or current PJM rules, we note that the IMM does not have the authority to enforce the PJM Tariff or PJM rules," FERC concluded.

The commission directed AEP to provide the Monitor the requested cost information within 15 days of the order.

PJM NEWS



OC Briefs

A Wild Month for Operations

VALLEY FORGE, Pa. — PJM experienced 77 emergency procedures in May, staff told attendees at last week's Operating Committee meeting.

Calling it a "busy month," PJM's Chris Pilong said the emergency procedures included the first time the RTO has had to order load shedding since implementing its Capacity Performance rules in 2015. (See *PJM Experiences First Load Shed in the CP Era*.)

The events resulted in a portion of the load forecasting error exceeding its 3% target for the first time since July. The on-peak forecasting error was 3.08%, and the off-peak 1.69%, putting the overall error at 2.38%.

While the error increased in some transmission zones, East Kentucky Power Cooperative posted a 3.3% error, the lowest level in the past 10 quarters.

Left to right: Bob O'Connell, Panda Power Funds; John Horstmann, Dayton Power and Light; Dave Pratzon, GT Power Group. | *© RTO Insider*

Load Shed Event

Pilong explained that five facilities were involved in the event. Three 138-kV lines in the area were on planned outages that day. A transformer and additional line tripping out of service triggered "multiple" contingency overloads, which potentially could have resulted in a cascading outage if another facility was lost, Pilong said. Based on that analysis, PJM ordered a pre-emptive load shed to reduce the contingency flow on the Edison-Kankakee line. Within 15 minutes of issuing the order, the transformer was restored, and PJM canceled the load shed nine minutes later.

"Given the timeline, we didn't need to, but we were definitely looking at [dispatching demand response or behind-the-meter generation in area] and considering those as well," Pilong said.

The load shed triggered performance assessment intervals (PAIs) that lasted about 30 minutes. While PAIs can trigger significant nonperformance penalties or performance bonuses, none resulted from the event, staff said. The incident was isolated to a small area of northwest Indiana that includes fewer than four generation owners, so PJM's confidentiality rules prevent staff from releasing any additional information without the owners' agreement. PJM's Adam Keech said staff are working with owners to see if they can agree on releasing anything else.

Keech said PJM determined which units were involved by looking at any units that could have increased output to help alleviate the constraint for which the load was shed.

Event Analysis to Follow

While he couldn't provide specifics on why the event yielded no penalties or bonuses, Keech advised stakeholders to "just remember we are in a year where we are not 100% CP," referring to the interim base capacity designation PJM implemented as it transitions to the CP requirement that a resource always be available. Base capacity doesn't have that requirement.

GT Power Group's Dave Pratzon asked that staff analyze why the three 138-kV lines were allowed to be on planned outages simultaneously because it potentially puts "a few unlucky generators" at financial risk for something they can't control.

"That's potentially a large dollar impact for something that potentially has nothing to do at all with generator issues," he said.

That question and the cause of the facilities tripping are "exactly what we're looking at as part of the follow up," Pilong said.

Several stakeholders asked PJM to find better ways to communicate the extent of the incident. RTO staff said they can only target messaging to the level of the transmission zone, even though the event affected a much smaller area, causing many stakeholders to wonder whether they were involved or not. Pilong said the conditions would have to be exactly the same for any refinement of the communication to be more selective, and that's "probably unlikely."

Besides, response to the event was unexpectedly quiet, despite the potential confusion.

"Oddly, we only got one phone call," Pilong said. "It was, to be honest, a little bit surprising."

Beyond that call, "there was no other anomalous behavior that was obvious or impactful," he said, adding that system operators' advice was the same as it would have been for any unit: follow the dispatch signal PJM provides.

Related Updates

Later in the meeting, PJM's Alpa Jani explained that the load-shed directive was posted at 1:34 p.m. and was effective for 1:22 p.m. Any units that receive system notifications for the AEP transmission zone received the message because the area around the Edison substation where the equipment tripped is not defined as a subzone.

In another presentation, PJM's Pete Langbein discussed how better "coordination" with behind-the-meter generation, also known as non-wholesale

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PJM NEWS

OC Briefs

Continued from page 32

distributed energy resources, could help decrease load forecast errors or mitigate load sheds.

PJM is proposing to identify all such non-wholesale DER of greater than 1 MW on an annual basis, primarily through public Energy Information Administration data. Transmission owners would verify the data and include additions as available so they can be modeled in PJM's planning and operations tools. The TOs would communicate downstream to the resources as necessary during events to avoid load sheds or dumps. Langbein said draft manual and Tariff language is being introduced in the DER Subcommittee and will move through stakeholder endorsement from there.

Security Initiatives

PJM's Colin Brisson reviewed security initiatives planned for the RTO this year.

"Critical infrastructure in geopolitics is becoming a higher-priority target" and has hit the energy sector, he said. "We're actually catching up to the curve where many companies are at."

PJM is implementing geo-IP blocking, which blocks outside computers from interacting with the RTO's network if its unique digital signature (or IP address) originates from "high-risk countries," which Brisson didn't identify. The technology will be rolled out "increasingly" throughout the year, he said.

The RTO is also implementing two-step verification, which means that along with providing the right password, users will have to tie their accounts to their devices using a "token" to log onto PJM's network. Once a token is verified, users will be able to log on from that device without going through the process again. Training will begin on Aug. 15 and "full production" to members is scheduled for Oct. 10.

DMS

PJM's Maria Baptiste announced the Data Management Subcommittee has decided to stop scheduling DMS-Joint meetings and instead hold them on an *ad hoc* basis as needed to address issues because of "very limited participation." DMS-Confidential meetings will continue on their existing schedule, and several parts of the DMS-Joint will transition to the Confidential group, including reviewing NERC lessons learned.

The subcommittee will still have work to do. PJM's Shaun Murphy announced that staff plan to ask the DMS to investigate why the quality of phasor measurement unit (PMU) data has been degrading. He presented a graph showing spikes in error percentages in various transmission zones through the RTO since February 2017. The issues include time, synch and drop errors, planned outages, missing samples and issues with engineering limits, such as threshold, noise and topology.

"On average, we're starting to see they typical error rate starting to climb," he said.

The DMS will investigate the impact of the data quality on applications that use the PMU data, enhancing the definition of "data quality," improving real-time data quality monitoring, reviewing data quality requirements in manuals and guidelines for device outages.

30-Minute Reserve Vote Deferred

PJM had hoped to receive OC endorsement for its planned procurement of 3,784 MW for real-time 30-minute operating reserves, but the vote was deferred because the topic wasn't included as a voting item on the agenda and came near the end of the three-hour meeting. Based on an analysis of potential reserve shortages, PJM estimates it should secure nearly 3,800 MW of a new 30-minute real-time reserve product. (See "30-Minute Reserves Target Set," *PJM Operating Committee Briefs: May 1, 2018*.)

Synch Reserve Response

The RTO experienced one synchronized reserve event of more than 10 minutes in the first quarter, PJM's David Kimmel said. Of the 1,897 MW estimated for the Tier 1 response, 510 MW responded, or 27%. Demand-side response was assigned all of the Tier 2 response. Of the 113 MW assigned, 58 MW responded, or 51%.

There were three events altogether, all of which occurred in January. Overall, 37% of Tier 1 estimates actually responded, or 2,029 MW. All of the 933 MW of generation assigned Tier 2 response responded, while 341 MW responded of the 397 MW of demand-side response assigned to Tier 2, or 86%.

The events resulted in $1.15 million of Tier 1 credits and $6,666 of Tier 2 penalties.

Skepticism of Gen Capability Changes Continues

Jerry Bell | *© RTO Insider*

Stakeholders remain skeptical of PJM's plan to revise procedures for generators' capability testing requirements, which has the potential to reduce generators' capacity injection rights (CIRs). For several months, PJM's Jerry Bell has been presenting data analyses to justify the changes to using median capacity factors, arguing that the RTO's current methods using average capacity factors overestimate what units can realistically be expected to provide. But stakeholders have been concerned about losing value they've already paid for. (See "CIR Questions," *PJM Operating Committee Briefs: May 1, 2018*.)

Generators are concerned that some existing or planned CIRs could be potentially stranded through PJM's proposal because it would reduce how a plant's output is measured for the purposes of qualifying for CIRs.

"PJM is being kind of cavalier with other people's investments. … There are other ways to do this," Dayton Power and Light's John Horstmann said. "I don't think you've addressed the transition nor the compensation adequately. … These interconnection investment costs are not linear."

He reiterated a request for a special session to discuss the implication of the proposed changes, to which PJM staff ultimately agreed.

Bell's presentation last week focused on the relationship between summer weather and production from hydroelectric dams. Among PJM's proposed changes is limiting facility testing to July and August and eliminating June from the testing window. Bell's analysis showed that hydro capability

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PJM NEWS

MIC Briefs

Seasonal Aggregation

VALLEY FORGE, Pa. — At PJM's Market Implementation Committee meeting last week, RTO staff outlined their proposal for registering aggregations of seasonal demand response resources that can't comply with the year-round requirements of Capacity Performance. The current process fails to account for some of the resources' overall capability depending on how they are aggregated.

PJM's Andrea Yeaton and Terri Esterly explained the proposed revisions, which would dispatch resources individually based on their seasonal ability but account for them cumulatively for the purposes of CP. They said the changes provide greater dispatch flexibility while also reducing the administrative burden and minimizing unaccounted-for capability.

Joe Bowring, PJM's Independent Market Monitor, expressed concerns about the proposal, notably in how it allows resources to aggregate across zones when the resources should be accounted for on a nodal basis as other resources are.

The proposal will be discussed at next month's meeting to provide more clarity. Staff want it to become effective for the 2019/20 delivery year.

Response to FERC's Cost Allocation Order

PJM's Ray Fernandez outlined staff's plans to address FERC's order on the RTO's procedure for allocating the costs of major transmission projects. The issue had dragged on for more than a decade in court orders and disputes between stakeholders, but after more than a year of negotiations, FERC last month approved a settlement agreement filed in June 2016 (EL05-121).

A large majority of stakeholders agreed to the settlement, which created a cost allocation formula for projects approved prior to Feb. 1, 2013, when PJM abandoned a "postage-stamp" method that billed all utilities in proportion to their load, regardless of where the projects were located. Several stakeholders, including Direct Energy and the Retail Energy Supply Association, had protested the agreement. (See *Despite Lengthy Negotiations, PJM Cost Allocation Settlement Still Finds Detractors*.)

Fernandez said staff were considering requesting a 30-day extension, which they filed later that afternoon. The motion requests an extension of the RTO's compliance filing deadline to July 30, seeking a FERC response by Thursday. PJM said in the request that it would affect the allocations for more than 100 baseline transmission projects.

The settlement revises the allocation for certain projects, effective back to Jan. 1, 2016, for which costs were assigned under the 100% load-ratio share method FERC had previously approved. Affected projects include those that are 500 kV or above and any associated "necessary lower-voltage facilities" as defined in PJM's Tariff. The allocation for all such projects will be split 50% on the original annual load-ratio share basis and 50% on the solution-based distribution factor (DFAX) method.

There is also a "black-box" settlement for projects from 2007 through 2015 that will have billing credits or charges based on revisions to Appendix C of Schedule 12-C in the Tariff that will be allocated over the next 10 years.

The revisions will show up in resettlements of wholesale bills: line 1108 for the reallocations and a new charge on line 1115 for the black-box settlement, Fernandez said. The reallocation charge will have to fit 30 months of resettlements into 12 months of billing.

"That's the way the settlement agreement is defined," Fernandez said.

GT Power Group's Jeff Whitehead asked

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dips in July and August compared to June.

"As river temperature increases, generator capability wanes, but the majority of the capability decrease can be attributed to the cooling towers that are placed in service incrementally as river temperature increases and control of thermal discharge is needed," Bell said. "These are the kinds of issues I'm having and why I want to see full plant testing."

He said a "blanket" RTO calculation is infeasible because conditions vary throughout the RTO's footprint and there will always be a situation where the analysis won't be applicable, "so I'd rather just have everybody test in July or August."

Several generation owners expressed concerns with the plan, such as the constraints of being able to test during a more compressed timeline.

"We just don't know how we would get this done in two months," Exelon's Sharon Midgley said.

"PJM is kind of cavalier with other people's investments. … There are other ways to do this," Horstmann said. "I don't think you've addressed it adequately. … The investments are not linear."

"I'm open to suggestions, but … I want to make sure that everybody understands that when you use the average capacity factor, you are overstating your ability to meet load during peaks and we need to rectify that situation," Bell said.

Some stakeholders suggested tailoring the requirements to specific unit characteristics, though Bell envisioned some concerns with that.

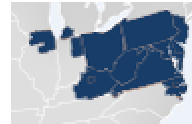
"Then it becomes somewhat discriminatory to some folks … but if we can work that out, I don't have a problem at all," he said.

He said units with "questionable test" results would likely be the first asked to retest under the new rules, but "there will probably be some folks that I would never even look at them." Other units likely to be contacted are those whose ambient conditions change during the season.

John Brodbeck of EDP Renewables said the plan creates CIR issues for generation in the interconnection queue that will fund network upgrades and "it sort of cries out for a problem statement." PJM staff did not respond to the suggestion.

— Rory D. Sweeney

PJM NEWS



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whether the resettlements would be accounted for as adjustments going back to 2016 or a one-time current resettlement.

"If it's an adjustment going back to 2016, it's going to be challenging to pass that through" to customers, he said. Retail energy suppliers "can probably only pass that through to customers you still have from 2016, which might be unlikely."

PAI Fallout

PJM's Adam Keech provided more information on the performance assessment intervals (PAIs) that occurred on May 29. PJM experienced its first PAIs — along with its first load shed — since implementing them as part of its major Capacity Performance overhaul in 2015. The incident occurred after a transmission line and a transformer at the Edison substation in American Electric Power's transmission zone tripped out of service, which — combined with three other transmission lines that were on planned outages — caused concerns about being able to deliver power in a section of northwestern Indiana. (See related story, "Load Shed Event," *PJM Operating Committee Briefs*, p.32.)

A PAI is triggered when PJM determines a supply reliability issue exists, and provides credits for generators that overperform their capacity commitments and penalties for those who underperform. No credits or penalties were assessed in the incident, which Keech noted was at least partly because PJM still has "base capacity" in this delivery year. Base capacity was developed as part of the transition to CP and doesn't have the same always-available requirements as CP resources. Because the event was localized to a small area that included less than four generation owners, Keech said PJM's confidentiality rules prevented him from releasing more information.

Direct Energy's Marji Philips voiced concern that how PJM assesses PAIs appeared "extremely discretionary." Keech disagreed, saying "there was no ambiguity on" the assessment and that the lack of charges or credits was "not because we exempted people arbitrarily."

"I think until we get more clarity, that's the only reasonable assumption," Philips said.

Citigroup Energy's Barry Trayers said that reporting the calculated bonuses and penalties shouldn't be a market-sensitive issue.

"I don't see the market gain or loss by reporting … winners or losers," he said. "I just don't see the results of this being a market-sensitive" issue.

Accounting for Maintenance Costs in Cost-based Offers

It remains unclear what package of revisions stakeholders are likely to endorse regarding whether maintenance costs are includable in cost-based energy offers. PJM believes they belong in plants' variable operations and maintenance (VOM) costs that are part of energy market offers, while the Monitor argues they are not short-run marginal costs, instead being avoidable costs that are includable in a unit's capacity offer. The issue was set to receive an endorsement vote at the May Markets and Reliability Committee meeting, but stakeholders instead agreed to kick it back to the MIC for further discussion. (See "VOM Remanded," *PJM Markets and Reliability Committee Briefs: May 24, 2018*.)

PJM's Tom Hauske presented an analysis that suggested the RTI's proposal would raise costs by $8.1 million per year. He argued the Monitor's assumptions on the issue were the worst case, short-term and low-probability. The Monitor's Catherine Tyler and Joel Romero Luna presented an analysis arguing that PJM's analysis misses

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the effect of higher unmitigated offers, fails to account for start-up and no-load costs and ignores cyclic starting and peaking factors.

They said 61% of combustion turbines they reviewed already have maintenance adders higher than the Energy Information Administration's benchmarks, as do 19% of the combined cycle gas-fired turbines. They also pointed to 2017 data that show a $1/MWh increase in energy offers equates to a $14 million increase in uplift. Their proposal would lower cost-based energy offers from the status quo, while the PJM proposal would raise them, they said.

Currently, an AEP proposal that used default EIA data is the main motion that was endorsed by the MIC for consideration at the June MRC. Greg Poulos, the executive director of the Consumer Advocates of the PJM States (CAPS), said one of his members plans to move the Monitor's proposal for an endorsement vote at the meeting.

Long-term FTRs Undercut Annual FTRs

Despite an impassioned argument from the Monitor's Howard Haas, stakeholders voted to endorse PJM's plan for revising its long-term financial transmission rights market. PJM's proposal received 178 votes in favor, 13 opposed and 53 abstentions for a favorability of 93%. The Monitor had offered as many as three proposals but dropped it to one for the vote. That proposal received 40 votes in favor, 147 opposed and 58 abstentions for a favorability of 21%. PJM's proposal was preferred over the status quo by 79%, or 131 votes in favor, 35 opposed and 77 abstentions.

Haas had argued that PJM's plan still gives away some of the transmission system capability that belongs to auction revenue rights holders because "there shouldn't be any residual revenue allocation" left to offer into the long-term auction and "the fact that some participants aren't taking advantage of the ARRs as they should be" shouldn't preclude them from receiving the full benefits available. The Monitor's plan

PJM staff left to right: Pat Bruno; Chrissie Stotesbury; and Chantal Hendrzak. | © *RTO Insider*

would require market participants to find someone willing to take the opposite flow of the sought position. (See "Long-term FTRs," *PJM Markets and Reliability Committee Briefs: May 24, 2018*.)

"The problem is you're still selling capability that belongs to the load," he said.

Calpine's David "Scarp" Scarpignato said it's not PJM's place to choose the best decisions for ARR holders and that "centralized planning" like that doesn't work.

"You have to allow that some market participants are going to make good decisions and others are going to make less-than-optimal decisions," he said.

Exelon's Sharon Midgley said her company's strategy to hedge its transmission costs "would be severely limited" under the Monitor's proposal because the company would "have to hope someone wants to take a completely opposite position … which is unlikely."

Black Start Fuel Security Sent to Problem Statement

PJM's David Schweizer announced that staff's proposal to develop fuel security requirements for black start units will be transitioned to the problem statement and issue charge structure. The RTO has been attempting to develop requirements for black start units that ensure fuel security, such as connection to multiple pipelines for gas-fired units or on-site storage. (See "Black Start Fuel Assurance," *PJM Operating Committee Briefs: May 1, 2018*.)

"PJM considers fuel assurance to be the ability of a unit to maintain full output during periods of fuel limitations caused by events such as seasonal weather extremes and high-impact, low-frequency events. Examples of high-impact, low-frequency events include pipeline failures or physical and cybersecurity events on a critical portion of a gas pipeline upon which black start resources may depend for fuel," PJM said in the problem statement. "Initial analysis of PJM's existing black start fleet indicates that approximately half of the units demonstrate fuel assurance, through dual-fuel capability, on-site fuel storage or multiple gas pipeline connections."

The discussion will be split between the Operating Committee and the MIC. The OC will cover fuel assurance requirements, testing requirements and transition process while the MIC will address compensation issues. PJM expects the issues to take six months and be implemented by August.

Balancing Ratio Recalculation

PJM's Pat Bruno presented two proposals for revising how the balancing ratio is calculated, recommending a more sophisticated fix but offering another in recognition of potential time constraints for having a solution implemented in time for next year's Base Residual Auction.

The simpler option would use the balancing ratios from actual PAIs whenever possible and estimate them from the remaining intervals with the highest peak loads until there are 360 intervals, or 30 hours, total. The more complex solution would revise the formulas that use the balancing ratio — the CP nonperformance charge rate, or performance penalty rate (PPR), and the market seller offer cap (MSOC) — to include "projected performance assessment intervals," which would be calculated for the delivery year as the average number of PAIs from the previous three delivery

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years. The MSOC would have a floor of 60 PAIs, or five hours, and the PPR would have floor of 180 PAIs, or 15 hours.

"It seems like you're picking numbers that feel good rather than backing into something from an empirical basis," Exelon's Jason Barker said.

Scarp and GT Power Group's Tom Hyzinski agreed that having different floors for the MSOC and PPR calculations was problematic.

"It's not a little bit off. It's off by a large amount, and it's highly problematic for operators looking to put competitive offers into the market. I understand you wanting to put them in, but they need to match," Scarp said.

As the discussion progressed, Scarp offered his own proposal that largely mirrored PJM's except in how many PAI events are used in the calculation. PJM agreed to organize a special session on the issue for June 19.

Stakeholders expressed concerns that PJM's formula could cause generators to lose all their annual capacity revenue in a short period. GT Power Group's Dave Pratzon said the estimates seem excessive, particularly in light of the recent PAI event, in which generators were on the hook despite the cause being a transmission constraint.

EnerNOC's Katie Guerry was concerned that, depending on the number of PAIs that occur, the PPR can double from $3,650/hour to $7,300/hour, while the MSOC would get smaller, starting at $255/MW-day with more PAIs and falling to $85/MW-day when there are none.

"I appreciate that you guys were trying to find a number that's not excessively high [and] … did a lot of work [in a short time period], but it was all internal," she said.

Bruno mentioned that FERC approved ISO-NE's hourly penalty rate of about $5,500/hour but noted that staff are open to feedback on the proposals.

DC Energy FTR Credit Policy Complaint to FERC

PJM's Bridgid Cummings explained the RTO's proposed revisions to its FTR credit policy, and CFO Suzanne Daugherty explained how its position related to a complaint on the topic that DC Energy filed at FERC (EL18-170).

PJM wants to implement a per-megawatt-hour minimum credit requirement to address potentially large FTR positions that have little or no credit requirements. It's also considering a monthly $100,000 deductible to the existing undiversified adder to address uncertainty and auction clearing disruption.

The per-megawatt-hour credit requirement dovetails with DC Energy's request for a 5 cent/MWh requirement, which Daugherty said is the minimum PJM is seeking.

"We think that is an improvement to the credit policy that we can absolutely support," she said.

She said staff are "not convinced yet" of DC's second request, a mark-to-auction requirement.

"I think some of the concern is … auctions are only once a month," so "clearing prices seem to jump around." Sometimes they would match, she said, but other times not, particularly closer to delivery. She acknowledged some market participants have high megawatt volumes in their portfolios, but none is in collateral default. Staff are targeting a July filing to respond.

The adder deductible would be used to reduce collateral calls that create credit uncertainty and potential delay of the market clearing, as they can't be applied until the auction is in the process of clearing. Cummings noted that 56 undiversified collateral calls were made from June 2016 to March 2018.

PJM is not recommending a deductible but wouldn't oppose it if stakeholders endorse the idea. Staff hope to have approved revisions implemented by this fall.

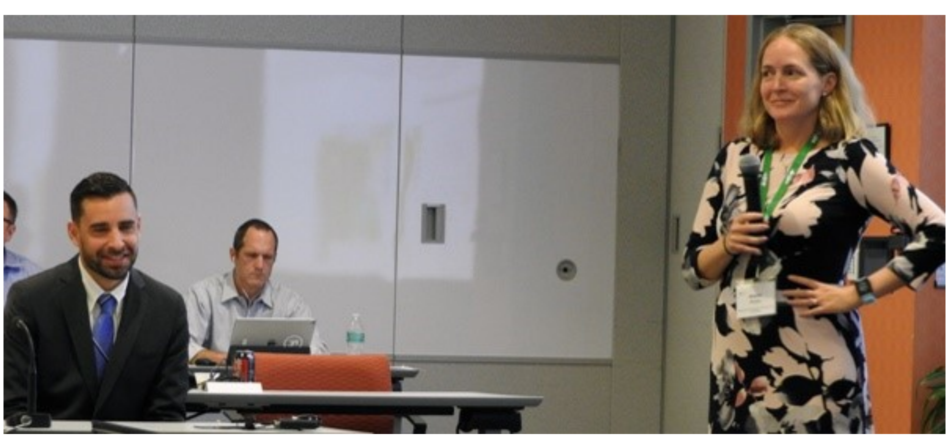
FTR Forfeiture

Midgley and Gabel Associates' Travis Stewart, representing NextEra Energy, presented specific examples of their concerns about FTR forfeitures. The analysis follows disputes with the Monitor at last month's meeting about whether current rules were having the intended effect of discouraging illegitimate activity or unreasonably harming market participants who are trying to make appropriate business decisions. (See "FTR Forfeitures," *PJM Market Implementation Committee Briefs: May 2, 2018*.)

"I would like to be able to use virtual transactions in the marketplace and at the same time use FTRs to hedge congestion risk," Midgley said. "The rule is doing more than it intended to do."

She provided an example of one hour in which Exelon was required to forfeit $47,000 in FTR revenue because a 200-MW virtual trade exceeded the testing thresholds for forfeiture on 18 FTR paths.

The forfeiture happened at 7 p.m. on Sept. 21, 2017. Six days later, NextEra experienced a similar issue with an 800-MW virtual trade at PJM's West Hub that created $2,078 in forfeitures. Stewart said that similar incidents across the month



Travis Stewart (left, seated) and Sharon Midgley | © RTO Insider

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PJM NEWS

PC/TEAC Briefs

Interconnection Procedure Split

VALLEY FORGE, Pa. — PJM is planning to add another volume to its Manual 14 series by splitting out the requirements for generation interconnection from Manual 14A into a separate Manual 14G, staff told attendees at last week's Planning Committee meeting.

PJM's Lisa Krizenoskas walked through the separation, noting that the new manual will be organized by generators under 20 MW, over 20 MW and other types of generation.

Staff said that rules for handling multiple generators behind the same point of interconnection will be addressed after the manual split is endorsed, but Ryan Dolan from American Municipal Power questioned why they wouldn't try to sort out both issues simultaneously. Krizenoskas said the new rules might delay the separation, which is meant to provide clarity for generators.

Load Model Selection

PJM's Patricio Rocha-Garrido presented PJM's proposed load model for the 2018 reserve requirement study focused on the 2022/23 delivery year. Staff recommend the same model used last year, along with again switching the peak week for regions external to PJM, known as the "world" in the analysis, to a week that doesn't coincide with PJM's peak.

Staff used 18 years of load history, 23 years of weather history and at least seven years of hourly loads to develop 78 model candidates. The candidates were compared to PJM's "coincidental peak 1" distribution analysis, which represents the highest load forecasted for the summer of the forecast year, using two separate approaches. The comparisons found that the 10-year model from 2003 to 2012 used in 2016 and 2017 remains the best choice because it was a close second to a nine-year model in the comparisons, but includes an extra year of load data.

The "world" peak week was again switched to not coincide with PJM's because the peaks haven't coincided in 11 of the past 19 years.

Dolan questioned why PJM doesn't use more-recent data to reflect changes in demand-side activity.

"The world is changing, and I think … [the] ability to control our load is much different from what it was in the earlier years of your data set," he said.

Facility Ratings Fine

PJM's Mark Kuras discussed staff's process for confirming transmission owners' facility ratings, concluding that "TOs have demonstrated that strict processes and controls are already in place to ensure facility ratings used in PJM operation are determined based on technically sound principles" and that "there are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check."

The discussion came after AMP and the PJM Industrial Customer Coalition criticized how TOs calculate the ratings. (See "Facility Rating Concerns," *PJM PC/TEAC Briefs: April 5, 2018*.)

TOs are required by NERC Standard FAC-008-3 to develop and adhere to a methodology for developing facility ratings, but they aren't required to publish it. Kuras noted that PJM publishes the final facility ratings on a public page.

"I think this presentation shows that, in and of itself, there are no issues with FAC-08" and how it's implemented, PJM's Aaron Berner said. "If that continues to be a concern, we can have those further discussions" about specific projects with proposing entities, he said.

Dolan said part of the concern is that in the process for determining whether they can develop a successful project bid, prospective developers must seek information that could make the incumbent TO aware of the potential proposal in a competitive window, which creates competition issues.

TO Planning Criteria Updates

Both Public Service Electric and Gas and American Electric Power provided updates to their planning criteria.

AEP announced it will no longer use Rate A for category P1 contingencies for lines above 345 kV and instead evaluate those facilities using Rate B for P1 through P7 contingencies.

PSE&G's Glenn Catenacci presented his

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accumulated to a total forfeiture for NextEra comparable to Exelon's $47,000.

"There's a lesson there, and it's not that we need to reduce the effectiveness of the rule. It's meant to change behavior," Bowring said. "The only impact of the rule is to take away your profits on an hourly basis. The point of the rule is not to be punitive."

Midgley argued that it also devalues FTRs subject to forfeitures and potentially requires load-serving entities to put risk premiums in customer rates, but Bowring said the fact that the forfeitures might cause Exelon or NextEra to devalue FTRs doesn't mean other market participants will.

"You suggested that load will be worse off from this, but you haven't demonstrated that, and I don't think it's true," he said.

PJM's Brian Chmielewski discussed the results of additional sensitivity analyses on the current forfeiture trigger from greater than or equal to 1 cent, to greater or equal to net 10% distribution factor. He found that forfeiture dollars would have been reduced by approximately 97% in September 2017 and 18 market participants would have received forfeitures instead of the 67 who did.

He concluded that the majority of constraints were "far away" from impacted FTRs, but Haas said that doesn't mean anything unless there's a "material impact." PJM is performing additional analysis on market-to-market flowgate virtual testing that it plans to present at next month's meeting.

"We are seeing a reduction in activity that is consistent with FTR forfeiture. That is a good thing," Haas said.

— Rory D. Sweeney

PC/TEAC Briefs

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company's updates, which modify pre-fault voltages, certain contingencies and other definitions. Dolan noted that several of the changes create requirements for building additional system infrastructure.

Glenn Catenacci | © RTO Insider

Among the changes was including non-firm transfers in models when considering common-mode outages. The change comes after FERC rejected a complaint from the New Jersey Board of Public Utilities seeking to revise how infrastructure costs are allocated, and that would have included several merchant lines into New York City that have changed their transmission rights to non-firm transfers. (See *PSE&G on the Hook for Bergen-Linden Costs*.)

Dolan questioned including non-firm transfers in the calculations because they wouldn't be included in allocating any costs for any system upgrades that subsequently become necessary.

"We think the people driving the need for transmission should be paying for it; however, there is a reliability issue," PSE&G's Esam Khadr said. "We need to address that reliability issue."

Khadr said he can't terminate non-firm transmission service, which hadn't been planned for previously because "it was not as prevalent as it is today."

"We have an obligation to all of our neighbors … to maintain reliability to the bulk power system," said PJM's Ken Seiler, who chairs the PC.

Staff haven't engaged with NYISO on non-firm transfers in planning criteria, but he said, "We'll evaluate it and certainly make any recommendations back to the Planning Committee."

Dolan and Khadr also sparred on whether to use breakers as an option for maintaining system reliability. The discussion came as part of PSE&G's clarification of how it will handle N-1-1 situations and its decision to not permit opening breakers.

"We're not going to plan a system by further degrading the system by opening breakers," Khadr said. "You're taking away that redundancy by taking away that breaker."

"Or utilizing its flexibility," Dolan pressed.

"We disagree," Khadr responded.

Nuke Closures Spark Transmission Upgrades

PJM's Phil Yum presented attendees at the Transmission Expansion Advisory Committee meeting 23 baseline projects sparked by FirstEnergy Solutions' announcement in April that it plans to shutter its three nuclear facilities within three years. (See *FES Seeks Bankruptcy, DOE Emergency Order*.)

Phil Yum | © RTO Insider

The projects would cost upward of $190 million combined, and because they are all within the three-year window for "immediate need" projects, they would all be assigned to the incumbent TO. PJM's Jason Connell confirmed that was the reason they can't be opened to a competitive bidding window. The projects are in the transmission zones of AEP, Duquesne, and FirstEnergy subsidiaries Allegheny Power Systems and Penelec.

Several of the projects are associated with the closure of the Davis-Besse nuclear plant, which is scheduled to deactivate on June 1, 2020. The projects can't be implemented until a year later, but PJM's planning group has discussed the issue with RTO operations and found operating measures that can mitigate the reliability impacts in the interim.

AMP's Ed Tatum questioned why PJM didn't include more details in the project descriptions. Connell said, "Certainly the scope of the timing is a little different" because of the deactivations. "We were on a very, very accelerated timeline" to determine "as best was we could do in the time frame that we had," he said.

Dolan questioned what might happen to the projects if FES ultimately decided not to deactivate the plants. Seiler dismissed the implication, saying, "Folks don't play games with this type of thing" because it includes jobs, communities and other large-scale factors. However, he acknowledged, "I'm not saying it couldn't happen in the future" based on a federal mandate or policy changes.

"We've never had any situation like this before. I agree it's not gamesmanship or anything like that, but things could change very quickly," Tatum said.

Seiler said money is already being spent on the engineering portions of the projects but said that if the decisions are reversed, "I think that would happen sooner rather than later."

— Rory D. Sweeney

Left to right: Jason Shoemaker, Ken Seiler and Anisha Fernandez. | © RTO Insider

SPP NEWS

Westward Ho: SPP Plans to Become RC in West

By Tom Kleckner

SPP's announcement last week that it will provide reliability coordinator (RC) services in the Western Interconnection should not come as a surprise.

The Arkansas-based RTO has long been interested in expanding into the Western market, where CAISO stands as the only system operator. The integration of Nebraska utilities in 2009 and the Integrated System in 2015 brought the RTO's footprint alongside the seam between the Western and Eastern Interconnections.

SPP's bid to add the Mountain West Transmission Group entities to its membership roll, though threatened by Xcel Energy's decision to withdraw from the effort, would expand the RTO into the Western Interconnection. (See *Xcel Leaving Mountain West; SPP Integration at Risk*.)

SPP said it intends to serve as an RC in the West by late 2019, leveraging "its expertise and systems to provide reliability and cost savings to Western utilities while lowering costs for its existing members." The RTO said it has sent letters to the Western Electricity Coordinating Council and NERC expressing that intention and its commitment to working with WECC and Western RCs to ensure reliability.

"We've shown consistently throughout our history an ability to coordinate people, systems and complex processes to keep the lights on," SPP CEO Nick Brown said in a statement, noting the organization has been performing reliability services since its founding in 1941 and was certified as an RC in 1997.

SPP said 28 Western utilities, representing about 200 TWh of net energy for load, have already signed letters of intent expressing interest in its reliability services. If it proceeds with its plans, the RTO will join CAISO and PJM Connext, a joint effort between PJM and Peak Reliability, in offering reliability services in the West. (See *Multiple Entities, Markets Now Beckon in West*.)

Peak not Surprised

Peak said it was not surprised by SPP's announcement.

"We are in a competitive market for RC services and the [balancing authorities] and [transmission operators] are quite rightly preserving their options so that they can determine the best fit for their organization," said Rachel Sherrard, Peak's vice president of external affairs. SPP's announcement "is not an indication of decisions made."

Sherrard said Peak will join SPP and CAISO in soliciting letters of intent from entities interested in taking their RC service from it. "Our process aligns with a recent request by WECC to the BAs and TOPs in the Western Interconnection to provide WECC with confirmation of which RC they will be using by Sept. 4, 2018," she said.

Plenty of Room

Asked whether there's room for another RC in the West, SPP pointed out that it is one of 10 RCs in the Eastern Interconnection, where it has a "proven history of working with neighboring RCs."

"We are confident our experience, tools and processes can contribute to enhancing reliability in the West," SPP spokesman Dustin Smith said in an email. "As we've done with RCs in the East, we are committed to working with Peak and CAISO to establish tools and data exchanges that ensure wide area visibility between RCs."

Smith said the announcement doesn't mean SPP's integration of the Mountain West entities is over.

"SPP continues to discuss potential RTO membership opportunities with [Mountain West], and we expect those discussions to continue as we work to develop our RC services offering parallel to that," he said.

FERC OKs Change to SPP 'Net Benefits' Test for DR

FERC last week approved SPP's May 2016 proposal to change how it measures the net benefits of demand response under Order 745 (ER12-1179).

The 2011 order requires grid operators to pay DR resources full LMPs when they are able to reduce demand and their dispatch is more cost-effective than generation, as determined by a net benefits test.

SPP's May 2016 compliance filing came in response to an April 2014 FERC order requiring the RTO to re-evaluate its net benefits test methodology using Integrated Marketplace data. The commission also asked SPP to propose any necessary changes to make its methodology compliant with Order 745 and to re-evaluate the appropriateness of its systemwide DR cost allocation mechanism.

The RTO proposed adjusting its net benefits test to use all available offer data and include non-peak hour data in the construction of supply curves. It said it would first average supply curves and then smooth the resulting average curve when performing the net benefits test.

"We agree with SPP that these two design changes to SPP's net benefits test methodology are appropriate given the greater availability of offer data in the Integrated Marketplace," the commission said. It ordered SPP to file Tariff revisions by July 5 implementing the two changes.

| SPP

FERC also accepted SPP's explanation that it did not need to adjust its DR cost allocation provisions, given there had not been any load-reduction activity in its footprint.

— Tom Kleckner

SPP News

Applications Being Accepted for Order 1000 Panel

SPP said last week it is accepting applications for industry experts to serve on a fourth independent panel to review Order 1000 transmission proposals in 2019.

The RTO forms the pool each year to manage competitive projects. A panel composed of experts from the pool will review, rank and score proposals for competitive projects approved for construction by the Board of Directors.

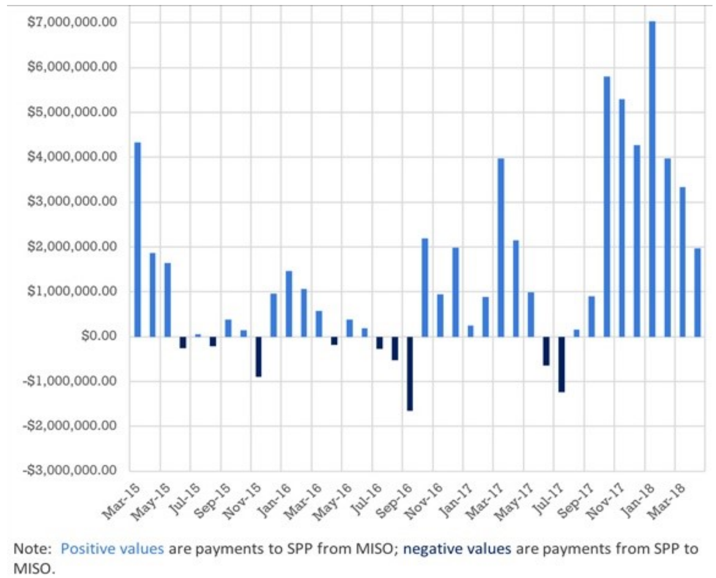
Interested candidates must have expertise in at least one of the following transmission-related areas: engineering design; project management and construction; operations; rate design and analysis; and finance.

Applications will be accepted through Aug. 31. Panelists will be selected based on a recommendation by SPP's Oversight Committee and approved by the board later this year. Those serving on the panel will be considered contractors and will be compensated through a monthly retainer and hourly rate.

More information can be found on SPP's website. Interested parties may also contact regulatory analyst Aaron Shipley.

Previous panels have awarded a single transmission project in Kansas, which was eventually canceled because of falling load projections. (See *SPP Cancels First Competitive Tx Project, Citing Falling Demand Projections*.)

MISO Racks up $1.97M in April M2M Charges



M2M history summary through April 2018 | *SPP*

For the ninth straight month and 17th of the last 19, SPP amassed market-to-market (M2M) payments in its favor from MISO during April.

SPP staff said during its Seams Steering Committee meeting last week that MISO incurred $1.97 million in charges, increasing its total payments to SPP to $53.3 million since the two neighbors began the process in March 2015.

The main cause of charges in April was the Nebraska City temporary flowgate in Omaha Public Power District's control zone. The constraint was binding for only 30 hours during April but racked up more than $717,000 in charges because of area outages, combined with lower wind generation and high south-to-north flows.

SPP's Nashua-Hawthorn permanent flowgate in Kansas was binding for 142 hours and accumulated more than $427,000 in M2M charges.

The committee met June 6 at Southwestern Public Service's offices in Amarillo, Texas.

— Tom Kleckner

FERC & Federal News

FERC OKs Reliability Standard on Fault Protections

By Rich Heidorn Jr.

FERC last week gave final approval to NERC reliability standards on training requirements and the coordination of protection systems to detect and isolate faults (Order 847, RM16-22).

Standard PER-006-1 (Specific Training for Personnel) sets training requirements for real-time operations personnel to ensure they understand the purpose and limitations of protection systems schemes. It also adds more precise and auditable requirements, FERC said.

PRC-027-1 (Coordination of Protection Systems for Performance During Faults) seeks to ensure protection systems operate in the intended sequence. It requires applicable entities to perform a protection system coordination study to determine whether the systems are operating in the proper sequence during faults or compare present fault current values to an established fault current baseline. In the latter case, a coordination study would be required only if there is a 15% or greater deviation in fault current values. The reviews are required every six years.

The commission's June 7 order also approved new and revised definitions for three terms: protection system coordination study, operational planning analysis and real-time assessment.

FERC, however, rejected a proposal in its Notice of Proposed Rulemaking to modify PRC-027-1 to require an initial protection system coordination study as a baseline, bowing to complaints by NERC and others.

NERC said that although the requirement could help reduce misoperations caused by a lack of coordination, it would be costly and burdensome. The reliability organization said it "expects that many entities will choose to do a full protection system coordination study ... for their more impactful [bulk electric system] elements" and that "it is highly likely that the overwhelming majority of entities have already conducted coordination studies for their protection systems."

FERC said it agreed that applicable entities will conduct studies on their significant facilities even without the requirement.

"We recognize the concern that were the NOPR directive adopted, applicable entities could be required to rerun protection system coordination studies for the sole purpose of generating compliance documentation, even if such entities already performed protection system coordination studies that remain valid but lack documentation to substantiate compliance," the commission said.

Dems Hit Coal, Nuke Bailout at House Hearing

Continued from page 1

Rep. Don Beyer (D-Va.) confronted DOE Assistant Secretary Bruce J. Walker over the directive at a hearing of the House Committee on Science, Space, and Technology's Subcommittee on Energy on Thursday. Walker, head of the Office of Electricity Delivery and Energy Reliability, responded tersely.

Beyer asked Walker about his pledge at DOE's Electricity Advisory Committee meeting on Feb. 20 that "'We would never use a 202 to stave off an economic issue. That's not what it's for.'"

"And now, FirstEnergy Solutions has recently asked that the department use a 202 to stave off an economic issue," Beyer continued. "Do we understand that you won't use a 202 for them?

"The 202 application from FirstEnergy is being reviewed by my department as we speak," Walker responded poker-faced.

The House Committee on Science, Space and Technology's Subcommittee on Energy listens to DOE Assistant Secretary Bruce Walker. | © RTO Insider

Beyer quoted the president of the Electricity Consumers Resource Council (ELCON), who said the DOE memo's proposed requirement that RTOs purchase capacity and energy from at-risk plants would "devastate" U.S. manufacturing.

"Have you calculated the costs on American business, specifically American manufacturing?" Beyer asked.

Walker: "I have not."

Beyer then cited ELCON's estimate that DOE's earlier Notice of Proposed Rulemaking to provide cost-of-service payments to plants with on-site fuel — made under Section 403 of the Department of Energy Organization Act — would cost $8 billion annually in PJM alone.

"Now the new plan nationalizes the 403 proposal, so I would expect that $8 billion is going to go up very significantly," Beyer

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FERC & FEDERAL NEWS

Dems Hit Coal, Nuke Bailout at House Hearing

Continued from page 42

said. "In putting together this draft plan have you estimated what this will cost the U.S. taxpayer?"

Walker: "I have not."

"I have to give you wonderful credit for being able to answer these things very, very tightly," Beyer responded. "I would suggest though ... this is something that you and Secretary Perry and others look very seriously at and should have numbers available for. I think it's within my purview as a member of this committee to ask you to go back and do the elementary research and report back to the committee on those two things please."

Walker said nothing, his expression unchanged.

Once the hearing had ended, Walker hurriedly left the room and did not make himself available for questions from reporters.

'False Narrative'

Beyer yesterday sent Perry a letter, co-signed by more than 30 Democrats, asking the Trump administration to "cease the false narrative that bailing out uneconomic energy sources in competitive markets is needed for electrical grid resilience."

Republican leaders of the committee made no reference to the order at the hearing, the topic of which was grid modernization. Ranking member Marc Veasey's (D-Texas) opening remarks, however, focused on the bailout order.

"The Trump administration is inventing emergencies to bail out coal and nuclear plants, while ignoring the real problems," Veasey said. "I'm sure the White House views this legal loophole that surfaced ... as an easy way to try to fulfill campaign promises, which is very bad and very unsound when it comes to energy policy. ... It would wreak havoc on our energy markets and create a number of misaligned incentives."

Rep. Paul Tonko (D-N.Y.) noted that he had worked with Walker on deregulating New York's electricity markets. He acknowledged the markets are not perfect, "but in 2018, the toothpaste is out of the tube, and drastic and unnecessary market interventions under the false pretense of an emergency to bail out uncompetitive generators like ones being discussed by the administration I think are unacceptable."

Also testifying at the hearing was energy consultant Rob Gramlich, former economic adviser to former FERC Chair Pat Wood III.

Gramlich said the directive ignores coal and nuclear plants' cyber risks, vulnerability to droughts and lesser ability than wind plants to ride through frequency deviations. "Fifty-year-old plants have outage rates that are typically three times as high as new plants," he added.

"All technologies .... have their strengths and weaknesses and contribute to reliability and resilience in different ways, but none of them are essential," he said. "Reliability comes from having reserves. In fact, each region already has a Strategic Generation Reserve. It's called a reserve margin."

FERC and NRC hold their annual joint meeting. | © RTO Insider

FERC Chairman Kevin McIntyre and NRC Chairwoman Kristine Svinicki talk more the joint meeting. | © RTO Insider

Retirements Discussed at FERC-NRC Meeting

Nuclear and coal plant retirements also were the subject of a joint meeting Thursday morning of FERC and the Nuclear Regulatory Commission at FERC headquarters.

Mark Lauby, NERC's senior vice president and chief reliability officer, discussed his organization's concerns about the loss of "conventional" generation and the increase in renewables and natural gas.

"When you look in certain areas and you've got 60 to 70% of their fuels [being procured] on spot [markets], it makes me worried that we have a risk there that we have to start thinking about addressing," he said.

But he said "firming up" fuel supplies is more important than fuel diversity. "Diversity really is only extremely helpful when you deal with things like Aliso Canyon, Fukushima, coal strikes. Diversity is helpful when you have those kind of unusual type events."

FERC Commissioner Richard Glick noted that nuclear plants can't provide frequency response, ramping or load following.

FERC Commissioner Rob Powelson asked if there was any validity to complaints that NRC's regulations are unduly burdensome and could be contributing to plant retirements. "Is that fake news?" he asked.

NRC Chairwoman Kristine L. Svinicki said for the nuclear retirements to date, "I think we could have radically changed our regulations. It would not have been enough to change the business case and the decisions to shut those units down. ... I've seen a little bit of the profit and loss statements, and I don't know what on earth the regulators could have done that could have saved those units."

Company Briefs

MasTec Gets $500M Contract For Puerto Rico Work

MasTec said June 4 it has received a $500 million contract from the Puerto Rico Electric Power Authority to complete repairing the island's transmission lines and begin modernizing its grid.

The company expects the work will take a year to complete.

More: *South Florida Business Journal*

Avista Issues RFP for Renewable Energy Projects

Avista on June 6 issued a request for proposals from renewable energy project developers capable of constructing, owning and operating up to 50 average MW (aMW) through one or multiple proposals with a minimum net annual output of 5 aMW.

The company said it wants to buy new renewable energy resources to offset market purchases and fossil-fuel thermal generation. Proposals are due by June 20.

More: *Avista*

Section of Columbia Gas Transmission Pipeline Explodes

A section of TransCanada's Columbia Gas Transmission pipeline in Moundsville, W.Va., exploded about 4:15 a.m. EDT on June 7.

TransCanada didn't have any employees at the site at the time of the blast, which didn't endanger any homes, officials from the Roberts Ridge Volunteer Fire Department told local news media.

TransCanada said the explosion could affect about 1.3 Bcfd of gas service.

More: *Reuters*

Xcel Files $2.5B Energy Plan in Colorado

Xcel Energy on June 6 filed with the Colorado Public Utilities Commission a $2.5 billion plan to add 1,110 MW of wind power, 700 MW of solar power and 225 MW of energy storage linked to solar projects.

Under its Colorado Energy Plan, Xcel also would close 660 MW of coal-fired generation at its Comanche Station in Pueblo about 10 years ahead of schedule and maintain its current 380 MW of natural gas generation.

The plan would enable Xcel to provide 55% of its power in Colorado from renewable sources and reduce its carbon dioxide emissions in the state 60% from 2005 levels by 2026, according to the company.

More: *Colorado Politics*

NRG May not Return Dunkirk Plant to Service

Dunkirk Steam Plant | *IBEW*

NRG Energy said June 7 it may not return its coal-fired power plant in Dunkirk, N.Y., to service as a natural gas plant because of the cost of reconnecting the plant to NYISO and the time the plant would have to spend offline before reconnecting.

NYISO recently told NRG that the cost of reconnecting the plant could exceed $100 million and that it might not be able to be reconnected until 2024, in part because the reconnection requires transmission upgrades in New York and Pennsylvania.

NRG has been planning to replace the plant's four coal-fired generation units with three natural gas-fired generation units.

More: *Observer*

FirstEnergy Announces Promotions in 2 Businesses

FirstEnergy on June 6 announced management promotions in its utility operations, and transmission and distribution businesses.

Haney

The company promoted Jim Haney to vice president of utility operations. Haney will oversee the operations and safety programs for FirstEnergy's 10 utility operating companies. He replaces Mark Julian, who is retiring after 38 years with the company.

FirstEnergy also promoted Mark Mroczynski to vice president of construction and design services. Mroczynski will oversee project management, transmission and substation design.

More: *FirstEnergy*; *FirstEnergy*

Duke Energy's Good Elected EEI Board Chair

The Edison Electric Institute said June 6 that Duke Energy CEO Lynn Good was elected to be the chairman of its board of directors. Good replaces PNM Resources CEO Pat Vincent-Collawn.

Exelon CEO Chris Crane and Xcel Energy CEO Ben Fowke were elected to be vice chairs.

More: *Edison Electric Institute*

Three Join Connecticut Power and Energy Society Board

Connecticut Power and Energy Society said June 4 that Kate Boucher, Graham Coates and Alex Judd have joined its board of directors.

Boucher is an associate in the Hartford office of Locke Lord; Coates is an energy, public utility and environmental attorney at Holland & Knight; and Judd counsels energy clients on regulatory, compliance and transactional matters at Day Pitney.

More: *Connecticut Power & Energy Society*

| *Connecticut Power and Energy Society*

FEDERAL BRIEFS

Idaho Power Sues EPA for Warmer Water in Snake River

Idaho Power on June 6 filed a lawsuit against EPA to force the agency to act on a 2012 request by the state of Idaho to allow warmer water in the Snake River below the Hells Canyon Complex where federally protected fall chinook salmon reproduce.

The company says in the lawsuit that the change could reduce the cost of power, saving customers up to $100 million over 50 years, and that studies by National Oceanic and Atmospheric Administration have concluded that changing the water temperature in the area below the hydroelectric complex would not harm the fish.

More: *The Associated Press*

Triad National Security Awarded Los Alamos Contract

The Department of Energy and National Nuclear Security Administration said June 8 they have awarded Triad National Security the management and operating contract for the Los Alamos National Laboratory.

The contract has an estimated value of $2.5 billion per year and has a five-year base period with an additional five one-year options, meaning Triad could be paid $25 billion over 10 years to run Los Alamos if all the options are exercised.

More: *National Nuclear Security Administration*

Amendment to Cut Yucca Mountain Funding from House Bill Fails

An amendment by Nevada Democratic representatives that would have removed funding for the proposed nuclear waste repository at Yucca Mountain from a Department of Energy spending bill was defeated by a voice vote in the House of Representatives on June 7.

The defeat means the funding bill still contains $267 million to restart the licensing process for the repository, which is located in Nye County, about 90 miles northwest of Las Vegas.

A Senate spending bill approved last month does not contain funding to restart the licensing process.

More: *Las Vegas Review-Journal*

Sens. Introduce Legislation To Remove Solar Tariff

Sen. Dean Heller (R-Nev.) and Sen. Martin Heinrich (D-N.M.) introduced legislation June 7 to remove the 30% tariff on imported solar panels imposed in January by President Trump.

Rep. Jacky Rosen (D-Nev.), Heller's likely challenger this fall, criticized Heller for waiting so long to take action. Rosen introduced a House version of the bill in April.

Heller's bill seems to face a hard road to passage, given that Senate Majority Leader Mitch McConnell (R-Ky.) said June 6 that the Senate was unlikely to take up a proposal from a group led by Sen. Bob Corker (R-Tenn.) that would require Congressional approval of tariffs.

More: *The Nevada Independent*

Perry Launches Competition to Boost Solar Manufacturing

Energy Secretary Rick Perry on June 7 announced the launch of the American-Made Solar Prize, a $3 million competition meant to boost U.S. solar manufacturing.

The competition has three phases. The first is to identify ideas, the second is to turn the selected ideas into proofs of concept and the third is to turn the proofs of concept into prototypes on which partners can perform pilot tests.

More: *Department of Energy*

USDA Grants $309M in Loans for Infrastructure Improvements

Assistant to the Secretary for Rural Development Anne Hazlett said June 7 that the Department of Agriculture is investing $309 million in 16 projects to improve rural electric infrastructure in 12 states.

The investments are loans being made through USDA's Electric Infrastructure Loan and Loan Guarantee program, which helps finance generation, transmission and distribution projects; system improvements; and energy conservation projects in communities with a population of 10,000 or less.

The loans will go to utilities in Alabama, Arizona, California, Colorado, Iowa, Kansas, Missouri, North Carolina, New Mexico, Ohio, South Dakota and Washington, which will use them to build or improve 1,660 miles of electric line serving rural homes, farms and businesses.

More: *Department of Agriculture*

EPA Seeks Input on Weighing Costs, Benefits of Regulation

EPA on June 7 issued an Advanced Notice of Proposed Rulemaking to seek input from the public on whether and how it should change its method for weighing costs and benefits in considering regulatory decisions.

"Many have complained that the previous administration inflated the benefits and underestimated the costs of its regulations through questionable cost-benefit analysis," said Administrator Scott Pruitt. "This action is the next step toward providing clarity and real-world accuracy with respect to the impact of the agency's decisions on the economy and the regulated community."

Conservatives have called for changes to how EPA accounts for costs and benefits. Environmentalists fear the result could hide the benefits of anti-pollution rules and regulations from the public.

More: *EPA*; *The Washington Post*

Reps Urge Pruitt to Scrap 'Transparency' Rulemaking

More than 100 House members, including four Republicans, on June 6 sent a letter to EPA Administrator Scott Pruitt, calling on him to withdraw the "Strengthening Transparency in Regulatory Science" rulemaking that he introduced in April.

"Contrary to its name, the proposed rule would implement an opaque process allowing EPA to selectively suppress scientific evidence without accountability and in the process undermine bedrock environmental laws," the lawmakers wrote.

The representatives also voiced concerns raised by scientists about the proposed rule, including that it would limit the agency's ability to use public health studies in which participants are anonymized for privacy reasons.

More: *The Hill*

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FEDERAL BRIEFS

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CAP Board Approves Contracts to Replace Power from Navajo Plant

The board of directors overseeing the Central Arizona Project canal on June 7 approved two power contracts to partially replace the electricity that the canal expects to lose next year when the embattled Navajo Generating Station closes.

Miners from the Kayenta Mine, which supplies coal to the power plant, had asked the board to put the vote on hold for three months to give Middle River Power time to put together a proposal to buy the plant and keep it open.

The contracts only cover about 14% of CAP's power needs, and CAP officials said that if Middle River or another entity can take over the coal plant, they'll consider buying power from it if the power is offered at a reasonable price.

More: *The Republic*

Trump Administration Actions Resemble Murray Proposals

Trump administration officials have taken actions that closely resemble measures contained in drafts of a half-dozen executive orders and other proposals that Murray Energy CEO Robert Murray submitted to the administration in its early days, according to documents recently released by the Department of Energy.

In two instances, DOE and EPA took steps to roll back what the coal-company executive called "anti-coal" policies within a month of him submitting proposals for doing so, *The Washington Post* reported June 6.

More: *The Washington Post*

$2.5B in Solar Projects Frozen Or Canceled After Tariffs

Reuters reported June 7 that developers of solar power projects told it they have canceled or frozen investments of more than $2.5 billion in large projects due to the tariff on solar equipment imposed by President Trump.

The amount is more than double the roughly $1 billion companies have said they would spend to build or expand solar equipment factories in the U.S. to take advantage of the tax.

The White House didn't respond to a request for comment.

More: *Reuters*

CO2 Emissions Intensity of Generation Fell 30% in 16 Years

The average annual carbon dioxide emissions intensity of power generation in the U.S. fell 30% between 2001 and 2017, according to a study by researchers from Carnegie Mellon University that was published in *Environmental Research Letters* on June 4.

The study attributes the decline to an increase in generation powered by wind and natural gas and a decrease in coal-fired generation.

The decline varied by region, with power plants in the Northeast posting the largest decline (58%) and power plants in the Texas region posting the smallest decline (27%).

More: *Environmental Research Letters*

NRC Names Second Resident Inspector at Clinton Plant

The Nuclear Regulatory Commission has selected Daniel Sargis to be resident inspector at Exelon Generation's Clinton Power Station in Illinois.

Sargis has assisted the resident inspectors at several sites and has completed a rotational assignment at Exelon's Braidwood Generating Station in Bracevill, Ill. He joins NRC Senior Resident Inspector Elba Sanchez Santiago at Clinton.

More: *Nuclear Regulatory Commission*

Global Renewable Power Additions Hit Record in 2017

A record 178 GW of renewable power generation capacity was added worldwide last year, according to REN21's annual renewables global status report, released June 3.

The amount of solar photovoltaic capacity added was also a record — 98 GW, up 29% from 2016, according to the REN21 report. Only 52 GW of wind power was added, 4% less than in 2016.

In all, renewables accounted for 70% of net additions to global generating capacity, the REN21 report said.

More: *Reuters*

DOE Funding 10 Teams to Develop Reactor Technologies

The Department of Energy said June 4 it is providing up to $24 million to 10 teams identifying and developing technologies to enable designs for less expensive and safer advanced nuclear reactors.

The funding is part of a new Advanced Research Projects Agency-Energy program, Modeling-Enhanced Innovations Trailblazing Nuclear Energy Reinvigoration (MEITNER), which ARPA-E developed in close coordination with DOE's Office of Nuclear Energy.

MEITNER teams will have access to DOE modeling and simulation resources and will coordinate regularly with team of experts from across the department and its National Laboratories.

More: *Department of Energy*

13 New Members Named to Nuclear Energy Advisory Committee

The Department of Energy's Office of Nuclear Energy on June 4 said it has appointed 13 nuclear science, business and industry leaders to its Nuclear Energy Advisory Committee (NEAC).

The new members join NEAC's 12 returning members.

NEAC was established in 1998 as part of DOE's Office of Nuclear Energy. It meets biannually to advise the secretary and the assistant secretary for nuclear energy.

More: *Department of Energy*

STATE BRIEFS

ARIZONA

NRDC: Modeling Shows Nuclear Plant Stays Open with 50% RPS

The Natural Resources Defense Council said June 5 that power-sector modeling shows the Palo Verde Nuclear Generating Station would stay open and operate around the clock under a scenario in which voters this fall approve a measure to increase the state's renewable portfolio standard to 50% by 2030.

The modeling was done by ICF using assumptions based on publicly available information developed by the NRDC.

Arizona Public Service, which owns 29.1% of the plant and operates it for a consortium of utilities, has said the plant would close if the measure were approved.

More: *Natural Resources Defense Council*

CALIFORNIA

More Solar than Gas Power In CAISO for 1st Time

Solar generation provided more of CAISO's power than in-state gas generation in May for the first time, according to an analysis of data released June 4.

Solar provided 3.02 TWh, or nearly 17% of CAISO's in-state generation. Gas provided 2.67 TWh, or around 15%.

Because CAISO doesn't track solar generation behind customers' meters, all of the state's solar generation systems actually produced as much as 50% more power than the ISO figures show.

More: *pv magazine*

SDG&E Gets OK for 5 Storage Projects, DR Program

San Diego Gas & Electric said June 4 the Public Utilities Commission has given it the go-ahead to add five energy storage projects totaling 83.5 MW and a 4.5-MW demand response program.

The utility said the projects will add lithium-ion battery storage facilities in San Diego and south Orange counties.

RES America, Advanced Microgrid Solutions, Fluence, Powin Energy and Enel Green Power will build the storage projects. OhmConnect will administer the demand response program.

More: *San Diego Gas & Electric*

MAINE

Report: 2k+ Jobs from Offshore Wind Industry Annually

The offshore wind industry could support 2,144 jobs in the state annually through 2030, according to a report released June 7 by nonprofit American Jobs Project.

"The Maine Jobs Project — A Guide to Creating Jobs in Offshore Wind" says the state is well-positioned to capitalize on the growth of the offshore wind industry because of the research into next-generation wind-power technologies being done in the state, the number of potential suppliers to the industry in the state and their expertise, and the state's large offshore wind resource potential.

At the same time, the report warns that creating jobs in the offshore wind industry will require the state to give clear policy signals, encourage collaborative efforts and provide continued assessments, policy planning and steady-handed leadership.

More: *American Jobs Project*

MINNESOTA

Great River Energy Aims for 50% Renewables by 2030

Great River Energy said June 6 it aims to use renewable sources to produce half its power by 2030, up from 25% now.

The wholesale power cooperative said it plans to reach 30% renewable production by 2020 and 40% renewable production by 2025.

More: *Star Tribune*

MISSOURI

Ameren Missouri Proposes $285M in Energy Efficiency Rebates

Ameren Missouri said June 4 it has filed with the Public Service Commission a proposal under the Energy Efficiency Investment Act for 26 energy efficiency programs that would make $285 million in rebates available to residential and business customers.

If approved by the PSC, the programs would run from 2019 to 2024.

More: *Ameren Missouri*

NORTH CAROLINA

Duke, Groups Agree on $2.5B Grid Modernization Plan

Duke Energy Carolinas, environmental groups and a group of retailers on June 1 filed with the Utilities Commission a compromise they reached on a grid modernization plan that would reduce the amount Duke spends to $2.5 billion over three years from $7.8 billion over 10 years.

The revised plan calls for Duke to harden its grid in hurricane-prone areas, deploy electric-vehicle charging infrastructure and energy storage and spend money on voltage optimization.

More: *Greentech Media*

PENNSYLVANIA

County Urges PUC to Keep Mariner Construction Halted

In a June 6 letter, Chester County Commissioners urged the Public Utility Commission to uphold a May 24 ruling by Administrative Law Judge Elizabeth Barnes suspending construction on the Mariner East 2 Pipeline and halting operation of the Mariner East 1 Pipeline, which runs along the same right of way.

In the letter, the three commissioners accused Sunoco Pipeline, which is building Mariner East 2 and runs Mariner East 1, of withholding emergency planning information from officials of towns along the Mariner East 2 pipeline's route, prioritizing profit over safety and creating mistrust among residents of properties along the

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STATE BRIEFS

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pipelines' path.

The PUC is expected to announce its decision on Barnes' ruling at its public meeting on Thursday.

More: *State Impact*; *The Lebanon Daily News*

RHODE ISLAND

National Grid Settlement Would Boost Bills 4.1% in First Year

National Grid on June 6 filed a three-year settlement agreement with the Public Utilities Commission that would hike the company's electric customers' bills 4.1% in the first year, 0.7% in the second year and 0.4% in the third year.

Other parties to the agreement include the Division of Public Utilities and Carriers, the Office of Energy Resources and the U.S. Navy.

"My obvious preference is no rate increase," Gov. Gina Raimondo (D) said in a statement. "However, I'm pleased that if this settlement is approved by the PUC, a significant portion of the proposed modest rate increase will be directed to make new investments in energy infrastructure, clearing the way for a more resilient, more efficient, cleaner and more renewable energy future."

More: *Providence Journal*

WEST VIRGINIA

Sierra Club Appeals PSC Order Authorizing Coal Cost Recovery

The Sierra Club filed an appeal in the Supreme Court of Appeals on June 4 of a Public Service Commission order authorizing Monongahela Power to charge its ratepayers for power it buys from American Bituminous Power Partners, the owner and operator of the Grant Town Power Plant.

The appeal, which was filed by Appalachian Mountain Advocates, a public interest law firm, argues that the order contains legal errors.

"In approving the pass through of the cost of buying power from an outdated, dirty coal plant, West Virginia's PSC has shown that it favors bailing out corporate polluters over prioritizing West Virginia ratepayers and local economies," said Justin Raines, Chair of the West Virginia Chapter of the Sierra Club.

More: *Sierra Club*

Five Questions on Trump's Coal, Nuke Bailout

Continued from page 1

nation's military bases, citing a 2008 Defense Science Board report that noted virtually all of the electricity supplying the nation's more than 500 military installations is generated outside the facilities. "Backup power at military installations is based on assumptions of a more resilient grid than exists and much shorter outages than may occur and is not sized to accommodate new homeland defense missions," the report said.

At the time, the bases' backup power was almost entirely diesel generators. Since then, the Defense Department has begun investing in microgrids and solar generation to allow their critical operations to continue operating during grid outages.

Preview?

Attorneys general from nine states and D.C. offered a preview of legal arguments against the DOE plan in challenging FirstEnergy Solutions' March 29 request to invoke 202c to prevent retirements of its coal and nuclear generation in PJM.

In a May 9 letter to Perry, attorneys general for Massachusetts, Connecticut, Illinois, Maryland, North Carolina, Oregon, Rhode Island, Virginia, Washington state and D.C. said 202c was never intended to rescue "inefficient generators."

"Section 202c explicitly authorizes the secretary to issue temporary orders only in wartime or other 'emergency' situations resulting from 'sudden' electricity demand spikes or supply shortages," they wrote. "Though the Federal Power Act does not define the terms 'emergency' or 'sudden,' the plain meaning of these terms indicates that Congress intended Section 202c authority to be invoked rarely, in response to acute events that demand immediate response."

DOE says it has deployed Section 202c on eight occasions, all in response to regional energy challenges. It has not previously been applied nationwide.

The department's memo contends that "Congress contemplated the use of the provision not merely to react to actual disasters, but to act in a preventive manner. A variety of man-made and natural threat conditions require … a federal agency ready to do all that can be done in order to prevent a breakdown in electric supply."

The AGs cited statements by FERC and PJM that potential plant closures do not pose an emergency. They also rejected a National Energy Technology Laboratory study cited by FirstEnergy that concluded PJM's demand during the December 2017-January 2018 cold snap "could not have been met without coal."

The study "mistakenly concludes that coal-fired generation was critical to reliability because coal-fired generation disproportionately increased during the cold snap," the AGs said. The extreme cold caused a spike in natural gas prices, briefly making coal generators more competitive.

"That certain resources were dispatched is not evidence the system lacked (or will lack during future events) other resources that could have been called upon instead to meet market demand and maintain reliability," the AGs said. "PJM has more than enough capacity to meet demand, even in extreme weather."

FAST Act

In addition to the DPA and FPA, the memo cites a third law as apparent authority, the 2015 Fixing America's Surface Transporta-

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Five Questions on Trump's Coal, Nuke Bailout

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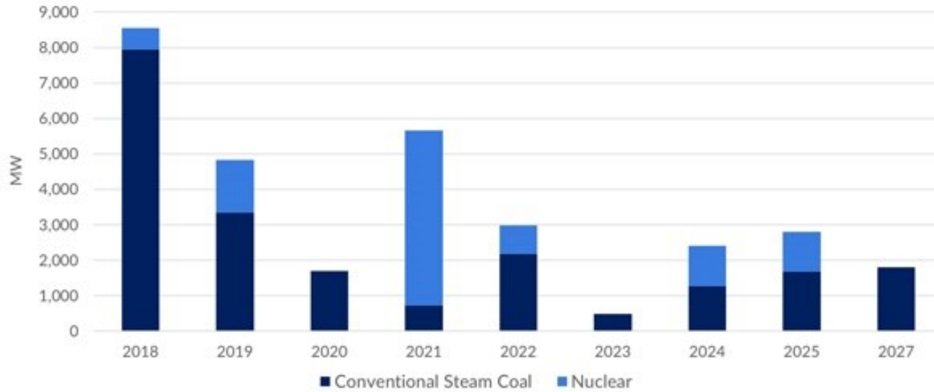

About 21.2 GW of coal generation and 10.1 GW of nuclear capacity are at risk of retirement through 2027. | *FirstEnergy Solutions, Energy Information Administration Electric Power Monthly, March 2018*

tion Act (FAST) Act, which amends the FPA to authorize DOE to order emergency measures to protect "defense critical electric infrastructure" following a presidential declaration of an imminent grid security emergency.

"Citing these three laws implicitly concedes that there is no single law that provides DOE with the authority to do what it wants to do," Ari Peskoe, director of the Electricity Initiative at Harvard Law School's Environmental & Energy Law Program, said in a podcast last week. "DOE's argument is that the whole is greater than the sum of its parts."

Peskoe said there are three paths opponents could take to attempt to block the bailouts, including a federal court suit to overturn the eventual DOE order and FERC complaints challenging individual wholesale contracts compensating the at-risk plants as not just and reasonable. "And separately you could also have more action at FERC arguing that these contracts are disrupting the larger market," he added.

Prior 202c Invocations

DOE's most recent invocations of 202c were limited to single generating plants and local reliability problems.

In December 2005, DOE granted the D.C. Public Service Commission's request to order Mirant Corp. to continue running its Potomac River Generating Station despite its inability to meet EPA's National Ambient Air Quality Standards, finding that the region otherwise faced a "reasonable possibility" of extended blackouts.

DOE noted that much of the district, including the FBI, State Department and other federal government agencies, were supplied only by the Mirant plant and two 230-kV lines connected to other generation. The loss of those sources also would threaten the city's water treatment center, which would be forced to release untreated sewage into the Potomac River if it lost power for more than a day, the department said.

The order required Mirant to keep the plant operating at a low level that allowed a quick start-up if either of the lines were lost. "Mirant and its customers should agree to mutually satisfactory terms for any costs incurred by Mirant under this order," the department said. "If no agreement can be reached, just and reasonable terms shall be established by a supplemental order."

Originally set to expire in 10 months, the order was twice extended for two months and once for five months. It was terminated on July 1, 2007, after the completion of new transmission.

Most recently, DOE in June 2016 granted PJM's request to order Dominion Energy Virginia to continue running its coal-fired Yorktown Power Station for 90 days despite its violation of EPA's Mercury and Air Toxics Standards. The department found that reliability in the Hampton Roads area of Virginia could otherwise be at risk during summer peaks.

PJM said it needed to keep the plant available because of delays in construction of the 500-kV Skiffes Creek transmission project, the subject of court fights because of the proximity of its James River crossing near historic sites.

DOE extended the 90-day order four times thereafter, most recently on June 8, 2018. That order expires on Sept. 9. PJM's most recent extension request estimated the transmission project will be complete in August 2019 and that Yorktown will not be dispatched after May 2019.

What's FERC's Role?

The five FERC commissioners are due to testify today before the Senate Energy and Natural Resources Committee in a previously scheduled oversight hearing. But it is unclear how much they will say about the proposed bailouts.

FERC was given no advance notice of the Trump directive and had received no additional information on it as of last Tuesday, when Chairman Kevin McIntyre met with reporters after speaking at the Energy Information Administration's Energy Conference. (See related story, *FERC Blindsided by Half-Baked Trump Order*, p.11.)

The draft memo had been prepared in advance of a June 1 meeting of the National Security Council, and DOE's plan will be reviewed by the NSC's Policy Coordinating Committees. FERC is not a principal in the process.

Although FERC has been excluded from policy deliberations thus far, the resilience docket the commission opened in January could play a role in any litigation, Christine Tezak of ClearView Energy Partners said in an analysis for clients Friday (AD18-7). FERC opened the docket after rejecting DOE's Notice of Proposed Rulemaking calling for price supports for coal and nuclear plants with on-site fuel. (See *FERC Rejects DOE Rule, Opens RTO 'Resilience' Inquiry*.)

Evidence that FERC, RTOs and states are moving aggressively on resilience could undercut DOE's legal standing, Tezak said. "We would expect the opponents of action … to reference the contents of this proceeding before FERC as evidence that the DOE's conclusions regarding resiliency are misplaced or in error."

If DOE's order survives legal challenges, the FERC proceeding could provide a path forward after the two-year study, Tezak said. "We think there is the potential for the FERC's resilience docket to provide information that could lead to DOE winding down if not ending altogether its potential market intervention."

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In addition, FERC will hear testimony at its annual technical conference on reliability July 31 to consider whether new NERC standards are needed to ensure "essential reliability services" (AD18-11). NERC has identified those services as including frequency and voltage support, ramping capability, operating reserves and reactive power. (See *NERC Report Urges Preserving Coal, Nuke 'Attributes'*.)

In an op-ed published Monday, Commissioners Neil Chatterjee and Richard Glick said natural gas pipelines should be subject to mandatory reliability standards, like those FERC and NERC enforce on the grid.

They noted that the Transportation Security Administration, which has responsibility for securing natural gas, oil and hazardous liquid pipelines, relies on voluntary cybersecurity standards. "In May 2017, TSA confirmed that it had just six full-time employees" overseeing pipeline security, they wrote.

"Given the high stakes, Congress should vest responsibility for pipeline security with an agency that fully comprehends the energy sector and has sufficient resources to address this growing threat," they continued. "The Department of Energy could be an appropriate choice: It is the sector-specific agency for energy security and recently created its own cybersecurity office."

How Will it Affect Emissions?

Because the bailout would cover both coal and nuclear plants, there is disagreement on how it would affect carbon emissions.

As of March, according to EIA, 21.2 GW of coal generation and 6.2 GW of nuclear capacity were scheduled to retire through 2027. EIA's list does not include FirstEnergy's announcement in late March that it will close its Davis-Besse, Perry and Beaver Valley nuclear plants, which total about 3.9 GW, by 2021.

Bloomberg New Energy Finance said in a report last week that emissions might be lower than the status quo if at-risk nuclear plants are kept running. It said that although capacity payments would keep coal plants available for backup, they may not actually run more under the Trump plan. Thus, the nuclear plants "could displace millions of tons of carbon dioxide a year" from coal plants, analyst Will Nelson said.

While nuclear plants have capacity factors of more than 90%, many at-risk coal plants operate less than 50% of the time.

But Varun Sivaram, fellow for science and technology at the Council on Foreign Relations, told Axios last week that freezing coal and nuclear generation at their 2017 levels — preventing them from the drops forecast by EIA — would mean coal-fired production would be 24% more than the additional nuclear generation in 2025. That would translate to between 0 and 5% higher emissions in 2025 relative to 2017, depending on the relative displacement of gas and renewables, he said.

How Will it Impact RTO Markets?

RTO officials told *RTO Insider* last week that, like FERC, they had received no information from DOE on the plan or when it might be finalized. (See *More Questions than Answers for FERC, RTOs on Bailout*.)

"We don't know if it will be a week, two weeks or months" before DOE acts, said one RTO official.

Craig Glazer, PJM's vice president of federal government policy, told the EIA conference last week that Trump's directive will "probably complicate" his RTO's struggle to deal with state nuclear subsidies. He said he fears a "half slave/half free" industry in which generators dependent on market revenues increasingly compete with those receiving cost-of-service payments or subsidies.

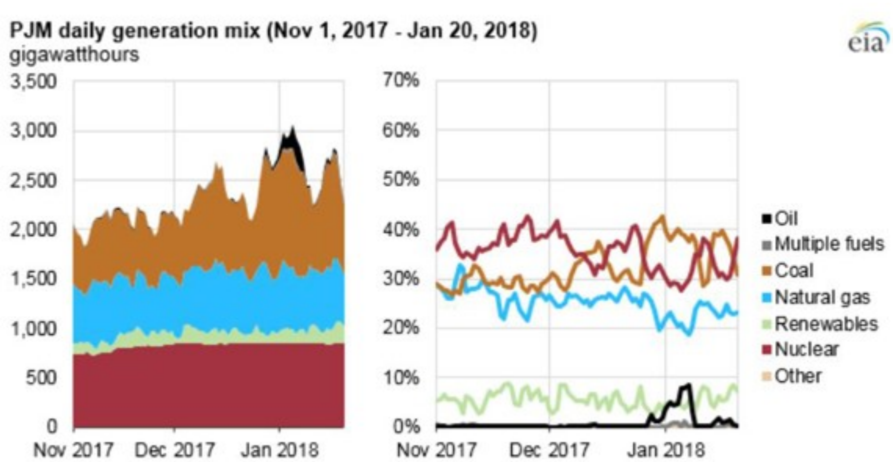
While RTO officials may not lead the legal challenges, their insistence that there is no emergency won't help DOE's defense. They point out that they have been successful in keeping plants running temporarily beyond their retirement dates when needed to prevent reliability problems. ISO-NE, for example, has asked FERC to waive its Tariff to keep Exelon's Mystic generating station running to address fuel security concerns. (See *Mystic Waiver Request Spurs Strong Opposition*.)

Brian C. Prest and Karen L. Palmer, fellows with nonpartisan think tank Resources for the Future, wrote last week about the questions raised by DOE's proposed Strategic Electric Generation Reserve. Among them: the size of the reserve, how generators would be procured and whether those selected be permitted to participate in or return to the energy markets.

Although the DOE memo provided no details, the fellows looked to the strategic reserve Germany is considering as it continues its phase out of nuclear power. The country has retired more than half of its nuclear generation since 2008 while more than tripling its non-hydro renewable capacity. It now gets half its capacity from non-hydro renewables versus 27% coal and nuclear and 14% gas.

Germany's reserve will be initially capped at 2 GW, about 2% of peak load, rising to as much as 5 GW (5%) after 2020. The reserve capacity will be procured through technology-neutral competitive auctions and open to demand response. The capacity would be used only as a last resort.

"It is not clear from the scant description in the memo how the SEGR would be procured, but the heavy-handed approach for the electricity purchase mandates suggests that competitive auctions are probably not under consideration," they wrote. "It seems more likely that plants would be chosen in



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the same way that they would be chosen for the electricity purchase mandates — based on a federally determined list of 'fuel-secure' generators (best interpreted as coal and nuclear plants)."

They note that Germany plans to address concerns the reserve will discourage new capacity investment by prohibiting reserve generators from re-entering the market. "Unfortunately, DOE's proposed order is specifically designed to send the message that government policy will find a way for unprofitable plants to return to the market, even calling its own order a 'stop-gap measure.'"

How Much Will it Cost?

Because so many details about the administration's plan are unknown, no one has produced an analysis of how much it will cost — including DOE itself. (See related story, *Dems Hit Coal, Nuke Bailout at House Hearing*, p.1.)

But some analysts produced estimates on

Energy Secretary Rick Perry testifies before a House subcommittee in October 2017. | © *RTO Insider*

the DOE NOPR rejected by FERC. It would have given cost-of-service payments to coal and nuclear plants in RTOs with capacity markets if they have 90 days of fuel on site.

ICF estimated the NOPR would cost ratepayers $1 billion to $4 billion per year between 2018 and 2030. The estimate was based on contracts for differences bringing money-losing generators to break even.

ICF caveated that the analysis might have underestimated the cost because it did not include recovery of and on capital. But it said the analysis also didn't account for the likelihood that wholesale electricity and natural gas prices will be lower than they would have been had the plants retired.

Energy Innovation Policy & Technology, which supports policies reducing greenhouse gas emissions, said the NOPR would have cost from $311 million to $900 million annually in PJM, ISO-NE, NYISO and MISO alone. The low estimate represents the out-of-market payments needed to bring units with negative net cash flows up to zero. The upper limit adds capital recovery and a rate of return on undepreciated capital and future capital expenditures.

"There are, of course, important differences between the resilience NOPR and the 202c actions being discussed by the Trump administration, but our study is a good rough estimate of the cost to keep the same group of uneconomic plants online," said Robbie Orvis, director of energy policy design for the group.