RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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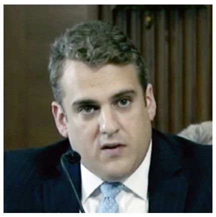
FERC General Counsel Tapped for Commission

By Rich Heidorn Jr.



FERC General Counsel James Danly

President Trump on Monday announced he will nominate FERC General Counsel James Danly to fill the Republican vacancy left by the death of Kevin McIntyre.

The commission was reduced to three members — Chairman Neil Chatterjee and Commissioners Richard Glick and Bernard McNamee — after the departure of Commissioner Cheryl LaFleur in August.

That has left the commission without a quorum in some cases as Glick, the lone Democrat, has been recusing himself from votes involving his former employer, Avangrid. (See related story, *FCA 13 Results Stand Without FERC Quorum*.)

Danly, formerly a member of the energy regulation and litigation group at Skadden, Arps, Slate, Meagher & Flom, was tapped to serve as general counsel in September 2017, a month after Chatterjee was named chairman.

Danly earned his J.D. at Vanderbilt University Law School in 2013 and a bachelor's from Yale University, where he studied classics and English.

After law school, he clerked for Judge Danny Boggs of the 6th U.S. Circuit Court of Appeals.

He was a managing director of the Institute for the Study of War, a military think tank in D.C., and served an International Affairs Fellowship at the Council on Foreign Relations.

A former U.S. Army officer, he served two deployments to Iraq and received a Bronze Star and Purple Heart.

During his first tour, with an infantry company in the Dora district of Baghdad, he authored and executed *Operation Close Encounters*, a tactical counterinsurgency program during the troop surge of 2007, according to a *biography* he provided to the Council on Foreign Relations.

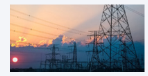
In his second tour, he served under General David Petraeus at Multi-National Force – Iraq.

If confirmed, Danly's term would end June 30, 2023.

In a *profile* in June, E&E News reported that Danly espouses a legal philosophy he calls the "humble regulator" — that FERC should work under a very narrow reading of the Federal Power Act and Natural Gas Act rather than using the agency's discretion to interpret the statutes.

E&E said Danly's philosophy was influenced by the conservative Federalist Society, which has served as a clearing house for many of Trump's judicial appointments. ■

Also in this issue:



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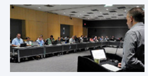

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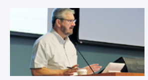

Despite Pushback, MISO Pursuing TO-only SATA (p.29)

Chatterjee Coal Country Forum to Consider 'Energy Transition'

By Michael Brooks

FERC Chairman Neil Chatterjee on Thursday released an ambitious, star-studded *agenda* for the commission's energy conference to be held Oct. 21 at the University of Kentucky in Lexington.

Dubbed the EnVision Forum, the daylong conference will feature 12 panels, three at a time, with some moderated by former FERC Commissioners Colette Honorable and Robert Powelson.

Panels will include "Transforming Transmission: Investing Today in Tomorrow's Grid," featuring former Commissioners Jon Wellinghoff and Phil Moeller, and "Emerging Issues in Organized Electricity Markets," with ISO-NE CEO Gordon van Welie, MISO CEO John Bear and interim PJM CEO Susan Riley.

Giving keynote addresses will be Murray Energy CEO Robert Murray, American Electric Power CEO Nick Akins, Energy Storage

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FERC's Glick Navigates Political Dynamic (p.7)

ERO Insider

ERO Insider's website is now live! Here are just a few of the stories we published this week:

Comments Open on Draft 2 of Inverter Standard

NERC Operating Committee Briefs: Sept. 10-11, 2019

NERC Standards Committee Briefs: 9-18-19

Check it out at www.ero-insider.com

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Counterflow

By Steve Huntoon

New York's Surreal New Deal

By Steve Huntoon

Indian Point nuclear plant | *Entergy*

Heard much about New York's Reforming the Energy Vision (REV) lately? No, I didn't think so. Remember how REV was supposed to empower customers and reduce their costs with all kinds of innovations in the traditional utility model? It was the most hyped regulatory initiative since the California restructuring some 20 years ago.

But as I wrote back in 2016: "Acronyms and visions abound, but there is no clear roadmap or even a clear destination."[1]

How prophetic. Other than squandering customer dollars on a few uneconomic demonstration projects,[2] REV as a customer-empowerment revolution that reduces customer costs is dead. RIP REV.

REV Absorbed into NY's Green New Deal

Instead, REV has essentially been absorbed into New York's own Green New Deal. Its Green New Deal has nothing to do with customer empowerment, reducing customer costs or transforming the traditional utility model.

Instead of transforming the traditional utility model, that model will be the vehicle for imposing billions of dollars in costs on customers/taxpayers to pay for top-down, centrally planned projects.

NY's Green New Deal is Surreal

Exhibit A is the planned enormous waste of customer/taxpayer dollars on offshore wind when the same subsidy dollars could procure many times that amount of onshore wind. I've written about that sad fact before.[3]

Exhibit B is the politically driven closure of the economic Indian Point nuclear plant and effective replacement of that emission-free generation with an equivalent amount of offshore wind (4,000 MW at about a 50% capacity factor) at a subsidy cost of about $830 million annually.[4] In other words, replacing Indian Point with offshore wind will squander $830 million of New Yorkers' money every year.

And when Indian Point is closed in 2020-21, with no telling when New York actually will have 4,000 MW of replacement offshore wind in service,[5] we know that fossil generation will be replacing Indian Point generation, and New York's carbon emissions will be going up, and even more so if New York succeeds in keeping new gas pipelines from supplanting coal generation. Don't expect data and reporting on all this.

Exhibit C is the subsidizing of other nuclear plants in New York to stay open. Yes, it's the theatre of the absurd when the economic nuclear plant is forced to close, with equivalent wind costing $830 million in subsidies and the allegedly uneconomic nuclear plants getting $500 million in subsidies to stay open.[6] I think I know how Alice felt in Wonderland.

Exhibit D is the planned enormous waste of customer/taxpayer dollars on batteries. Yes, I've written about batteries several times.[7]

But, sorry, New York seems to have a particularly wasteful approach to subsidizing batteries: Simply subsidize batteries.

New York's first battery project is the Key Capture Energy project, which New York claims "will help reduce greenhouse gas emissions. The 20-MW energy storage system supports Gov. Andrew M. Cuomo's Green New Deal." The state's press release drones on with self-congratulatory quotes from just about everybody and lots of promotion of New York's Green New Deal.[8]

Now here's the thing: This battery project isn't

Counterflow

By Steve Huntoon

going to reduce carbon emissions one iota. This battery provides regulation service and moves off its set point at 50% of capacity only as signaled.[9] The net effect on generation is trivial with no way of knowing whether carbon emissions are trivially increased or trivially decreased.

On to the much-ballyhooed 300-MW storage procurement by Consolidated Edison. The request for proposals is of course long and complex, but it asks *nothing about actually reducing carbon emissions.*[10] It's storage for the sake of storage.

On to the New York State Energy Research and Development Authority implementation plan for storage, with requirements and metrics for bulk storage, *none of which involve actually reducing carbon emissions.*[11] More storage for the sake of storage.

Last but not least is the idea of replacing peaker plants with batteries. It ought to be obvious that replacing seldom-run peaker plants with batteries won't materially reduce carbon emissions because seldom-run peaker plants seldom produce carbon emissions. And even if they did run more it would beg the (unanswered) question of what would be used to charge the batteries.

And here's a gut-check conclusion of New York Public Service Commission staff's study of the subject that nobody seems to appreciate: six-hour batteries could provide equivalent generation for only 275 MW of the state's existing peaker fleet of 4,500 MW.[12] Let's think about this. The type of generation that batteries ought to be able to replace is peakers, but when operational analysis is done, it turns out that only 6% of existing peakers could be replaced by batteries.

So what's the peaker replacement reality? Little carbon emission benefit and little operational feasibility.

Nota Bene

All this is fair warning to everyone everywhere when politicians pull numbers out of thin air — like New York's 9,000 MW of offshore wind and 3,000 MW of storage — and tell the political appointees to just do it.

The politicians get the applause lines, and the customers get the shaft. ■

[1] http://energy-counsel.com/docs/You-Say-You-Want-a-REVolution-Fortnightly-February2016.pdf.

[2] As I said about the utility residential solar programs: "REV demonstration projects at least demonstrate one thing: Utilities shouldn't be running residential solar programs."

[3] http://energy-counsel.com/docs/Offshore-Wind-Edifice-Complex.pdf. By the way, there are more than 5,000 MW of onshore wind in NYISO's interconnection queue, https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx/c0fe9a9b-7011-ab05-0f51-fd4ad0ef33f0 (sorting on wind for total of 18,976 MW and subtracting 13,632 MW of offshore wind).

[4] Indian Point's 2,144 MW capacity times 90% capacity factor is 16.9 million MWh. https://www.eia.gov/todayinenergy/detail.php?id=29772. New York has not disclosed subsidy information, but if we use New Jersey's $98.10/MWh price as a proxy (conservative given New York's union labor requirement) https://www.scientificamerican.com/article/major-u-s-offshore-wind-projects-still-face-hurdles/, and subtract the $49/MWh energy price in the Long Island zone in 2018, https://www.nyiso.com/documents/20142/2223763/2018-State-of-the-Market-Report.pdf/b5bd2213-9fe2-b0e7-a422-d4071b3d014b (pdf page 8), then the annual subsidy cost is 16.9 million MWh times $49.10/MWh, which equals $830 million.

[5] The first 1,700 MW have an (optimistic) in-service date in 2024. https://www.nationalfisherman.com/mid-atlantic/new-york-signs-1-7-gigawatt-deal-for-offshore-wind-energy/.

[6] https://www.nytimes.com/2016/08/02/nyregion/new-york-state-aiding-nuclear-plants-with-millions-in-subsidies.html.

[7] http://energy-counsel.com/docs/Cue-the-Pixie-Dust.pdf; http://energy-counsel.com/docs/Grid-Batteries-Kool-Aid-Once-More-with-Feeling-RTO-Insider-12-5-17.pdf; http://energy-counsel.com/docs/Battery-Storage-Drinking-the-Electric-Kool-Aid-Fortnightly-January-2016.pdf.

[8] https://www.nyserda.ny.gov/About/Newsroom/2019-Announcements/2019-09-12-NYSERDA-Announces-Completion-of-Largest-Battery-Installation-in-the-State.

[9] https://dailygazette.com/article/2018/07/05/20-megawatt-battery-facility-planned-in-stillwater. ("'We'll leave it probably half-charged,' [Chief Development Officer Dan] Fitzgerald said, so that it can go either way.").

[10] https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/bulk-energy-storage/bulk-storage-request-for-proposals.pdf?la=en.

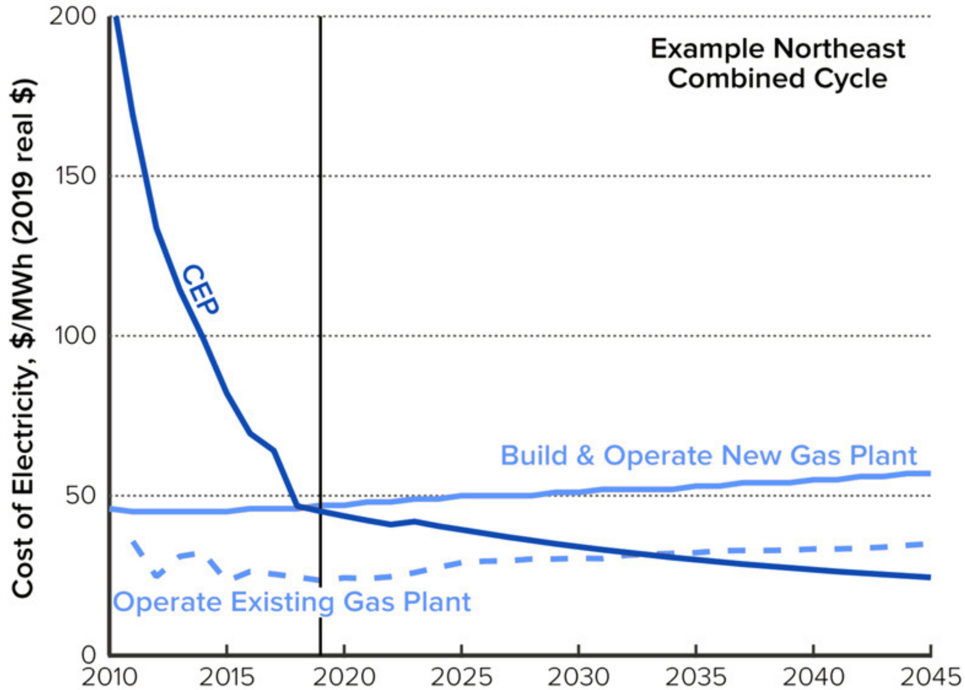
[11] http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=230734&MatterSeq=55960.

[12] The PSC staff study is here, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2F0A202D-CAB9-4961-96F3-56AEA67C6052} (pdf page 24). Four-hour batteries could replace 83 MW, and eight-hour batteries could replace 509 MW. Of course, eight-hour batteries cost twice as much as four-hour batteries. Adding solar to batteries could replace more megawatts, but of course that adds even more costs.

Stakeholder Soapbox

The Risky Investment Case for New Gas-fired Power Plants

By Mark Dyson, Chaz Teplin and Grant Glazer



Historical and project evolution of CEP costs. | *Rocky Mountain Institute*

Last week, RTO Insider published an *op-ed* from Steve Huntoon that challenged the approach and findings of the *latest report* from Rocky Mountain Institute (RMI) on "clean energy portfolios" (CEPs), defined as combinations of renewables, storage and demand-side management programs that, together, can provide the same energy and reliability services as a gas-fired power plant.

Our study, using detailed modeling approaches and robust, region-specific data, found that 90% of gas plants currently proposed for construction face significant risk of competition from CEPs, and associated stranded-cost risk within 10 to 15 years.

The RMI team welcomes feedback and respectful discourse from all perspectives as it relates to our work and its implications, but Huntoon's article misses the mark by misrepresenting our motivation, oversimplifying our approach, and downplaying the significance of key findings relevant to investors and other RTO market stakeholders. In dismissing our study as relying on "pixie dust," Huntoon ignores evidence of the fundamental transition underway in the electricity industry and reflects a view of industry dynamics from a decade or more ago that is unsuited to today's landscape.

An Evidence-based Study Focused on Financial Viability and Risks

RMI is an independent research and consulting firm focused on market-based, profit-motivated solutions for clean energy. Having observed the plight of the coal industry and its investors in recent years, we set out in our study to answer a simple question: Is gas-fired generation heading down the same pathway that has led coal plants into financial distress and early retirement?

There is evidence that this is already occurring. The *Panda Temple project bankruptcy* in 2017 was an early warning signal, and the *planned closure of a 10-year-old gas plant* in California announced in June 2019 suggests a growing trend. Nationally, investors are taking notice, with final investment decisions in new gas capacity *declining* each year since 2014, and capacity factors for a growing share of new combined cycle gas projects already *falling significantly below expectations*.

With more than $100 billion in planned gas infrastructure investment through 2025, we set out to examine the risks to shareholders and ratepayers if those investments don't pan out in today's rapidly changing competitive environment.

A Transparent Approach with Conservative Assumptions

Huntoon's first claim about our study is that "numbers are lacking: It's not possible to validate the data and algorithms." In fact, we clearly cite every source of data that we rely on, all of which are drawn from industry-standard sources (see pages 27-29 and the technical appendix). We also reference the full mathematical formulation of our model published in our initial, *2018 report* (pages 29-37 of the appendix).

Huntoon then challenges our inclusion of energy efficiency and demand response in aggressive quantities. In fact, our estimates are consistent with definitive resource potential assessments from the *Electric Power Research Institute*, *FERC* and others, as well as recent evidence from leading utilities. To name just a few examples from the past year: *Xcel Energy* is including more than 800 MW of EE in its integrated resource plan in Minnesota; *Portland General Electric* is leaning heavily on demand flexibility in its 2019 IRP while building no new gas; and Glendale Water & Power ran a competitive, all-source procurement that *resulted* in new EE, DR and other customer-sited resources accounting for approximately 20% of new capacity needs.

Huntoon also argues that it is illogical for us to consider EE and DR only as part of CEPs, and not as complements to gas-fired generation. However, our optimization-based modeling approach shows directly how EE and DR are natural complements to zero-marginal-cost generation from wind and solar, with regionally distinct portfolios that leverage resource diversity and load profile characteristics across seasons and hours. More importantly, in making this argument that a combination of EE, DR and a small gas plant might be less costly than either a big gas plant or a CEP, Huntoon actually bolsters the case that EE and DR are a competitive threat to gas investments if planners do not account for them when sizing projects.

Finally, Huntoon takes issue with the possibility that batteries included in CEPs may be charged with "pixie dust" — or more accurately, energy from fossil-fired generation. To be clear: That is a feature of our analysis, not a bug. This assumption that batteries can be

Stakeholder Soapbox

charged from the grid during off-peak hours is consistent with the reality of electricity markets, where off-peak capacity is readily available. Our model also carefully subtracts the energy required for battery storage when calculating the CEP's net monthly energy generation.

A CEP shouldn't be restricted from leveraging the current system any more than any other grid asset. Similarly, we would not argue that a new gas plant must keep the lights on without help from other, existing generators. Huntoon's argument is irrelevant as it pertains to our central finding: that CEPs can compete and win on gas plants' own turf.

Risks and Uncertainty in an Investment Case for New Gas Capacity

In short, the challenges made by Huntoon against our work are inaccurate, irrelevant or both. Our study finds clear evidence that the majority of proposed gas generation projects are uneconomic to begin with and, if built anyway, will likely lose money well ahead of their expected economic lifetimes. Far from relying on "pixie dust," our analysis reflects the current state of the market and the inevitable outcomes of further innovation and cost declines in renewables and storage. Perhaps the "pixie dust" that Huntoon refers to is, instead, required to believe forecasts of new gas plant profitability even in light of current market trends and their clear implications. ■

FERC/Federal News

FERC's Glick Navigates Political Dynamic

By Tom Kleckner

HOUSTON — The FERC that Richard Glick joined as a commissioner in November 2017 was nothing like the "sleepy agency" he came to know during his many years as a D.C. insider.

"For the most part, it's been a nonpartisan agency. The vast majority of orders have gone out on non-party-line votes," Glick said in keynoting the 18th Annual Gas and Power Institute last week near the heart of the nation's energy industry.

"That's starting to change, for a variety of reasons," he said. "With technology changes, these issues are becoming much more contentious. The more traditional technologies are clearly fighting to protect their turf, and the newer technologies are fighting to get a part of that. That's posed some issues for us."

But the greater issue is the political divide, said Glick, the lone Democrat among the three men sitting on the commission.

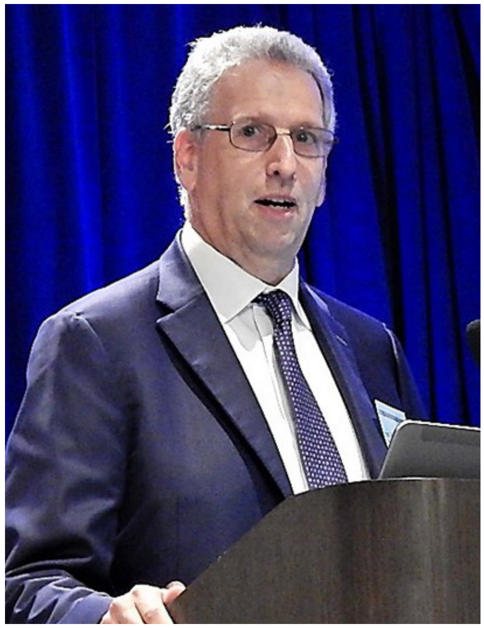
"Some of atmosphere at FERC is a little more tense than it has been, in large part because of what's going on in Washington, D.C., in general," he said. "It's a different atmosphere than before, and FERC is reflective of that."

Glick said he has dissented a "lot more" than he thought he would have when he joined FERC. Most recently, he argued that the commission's recent move to adopt proposed revisions to how it administers the Public Utility Regulatory Policies Act of 1978 would essentially "gut" a law that has spurred renewable energy growth. (See *FERC to Reshape PURPA Rules*.)

Glick has often been the only commissioner taking a stand against approving gas pipelines and LNG projects. He has repeatedly expressed concerns about the lack of greenhouse gas considerations in commission rulings and now has begun charges that FERC is "scrubbing" references to climate change from its orders. He noted that boilerplate language encouraging developers to take GHG emissions into consideration has been removed from recent orders.

"All of a sudden, that's been taken out of the orders," he said. "The commission is choosing to stick its head in the sand and not consider greenhouse gas emissions, and that's problematic."

"Glick is the lone voice in the wilderness," Tom Hirsch, a D.C.-based lawyer with Norton Rose Fulbright, told attendees.



FERC Commissioner Richard Glick | © *RTO Insider*

"My beef with the majority, and what FERC has been doing for a number of years, is relying on precedent agreement, and not even arguing it," Glick said. "We've been called a 'rubber stamp' for the pipelines. That's not always true … but I don't think we've done our job [in determining a project's need] as we should."

Compounding Glick's frustration is the turmoil surrounding FERC itself. The commission, which struggled to reach a quorum in 2017 following the change in administrations, is now back to three members following Cheryl LaFleur's departure in August. (See *FERC Heaps Praise on Departing LaFleur*.)

Normally, the administration would nominate a candidate from each party to fill the two vacant seats, maintaining a 3-2 split favoring the party holding the White House. "That's been the tradition," Glick said.

The White House late on Monday night announced President Trump intended to nominate FERC General Counsel James Danly to fill the empty Republican seat. (See related story, *FERC General Counsel Tapped for Commission*.) Asked last week if he was familiar with what was just a rumor at the time, Glick said, "I hear the same things you do. I will guarantee you the White House did not call me up and ask my opinion.

"Even if you change one commissioner for another, it takes a while to get used to each other's rhythms," Glick said. "There's a lack of stability. I'm very hopeful that we will get another commissioner [soon]."

FERC Chairman Neil Chatterjee declined to comment on Danly during an earlier September visit to Houston.

Compounding matters is a recent determination by FERC's designated agency ethics official (DAEO) that Glick should continue to recuse himself from proceedings related to his former employer Iberdrola USA (now Avangrid), again making quorum an issue, particularly in a key proceeding related to PJM's capacity market. (See *Glick Recusal May Mean No MOPR Ruling Before December*.) Glick said he initially understood the two-year recusal would have expired two years after he left Avangrid in February 2016. In reality, he was later told, the clock started ticking when his term began in November 2017.

"I think he made an honest mistake," Glick said of the DAEO's first ruling.

The same ethics office has advised Commissioner Bernard McNamee that he doesn't have to recuse himself from the commission's grid resilience proceeding, unless it "closely resembles" the debate over the coal and nuclear subsidies he helped write at the Department of Energy.

Still, Glick soldiers on. While appearing reserved at first glance, he seems comfortable speaking out while manifesting a wry sense of humor.

When he mentioned he disagreed with a fellow commissioner, a reporter tried to pry Glick into naming names. "I think I disagree with both of my colleagues. I like them, but we disagree on policy."

ERCOT Monitor: August 'High Excitement' for RT 'Geeks'

Also speaking at the conference, Potomac Economics' Beth Garza, executive director of ERCOT's Independent Market Monitor, described the Texas grid operator's ability to meet customer demand during scarcity conditions this August as "high excitement for those of us who are real-time energy market geeks."

ERCOT called its first energy emergency alerts (EEAs) in five years this summer and relied on emergency response service and DC tie imports to meet record-breaking demand. However, the two EEAs weren't called on days when load reached record levels, but during

FERC/Federal News

days when West Texas winds died down before the late afternoon peak. (See "ERCOT CEO Briefs Commission on Summer Performance," *Texas PUC Briefs: Aug. 29, 2019*.)

"In ERCOT, high loads used to be driven by high temperatures, but it's no longer that," Garza said. "Now, it's, 'Is it going to be hot? Is it going to be still? Now, the third piece is, 'Is it going to be cloudy?' Those are the drivers for pricing and price outcomes."

Prices briefly hit $9,000/MWh during both EEAs. "Prices should be reflective of the conditions you are in," Garza said. "If you are in scarce conditions where you may have to curtail load, the price should be high."

Geek that she may be, Garza noted that ERCOT's real-time energy prices averaged $50.70/MWh through August, a 40% increase year-to-date over 2018 ($36.20/MWh). This despite a 15% decrease in natural gas prices so far in 2019.

But, Garza asked, is that enough for people to "plunk their money down and build a power plant" to take advantage of scarcity prices? She would only point to the 2020 summer's forward on-peak prices, which spiked to more than $400/MWh in August but have since dropped to $250/MWh, and let her audience decide.

Glick offered his own positive outlook on the ERCOT market.

"Texas has a very unique market," he said. "It's an energy-only market, yeah, and prices spike during certain hours in the summer, but contrary to predictions, the lights didn't go out."

Questions over Capacity, Traditional Markets

Glick also shared his insight on capacity markets, which he said are one of the biggest policy issues before FERC. He suggested participants are losing faith in the markets as they attempt to integrate renewable generation.

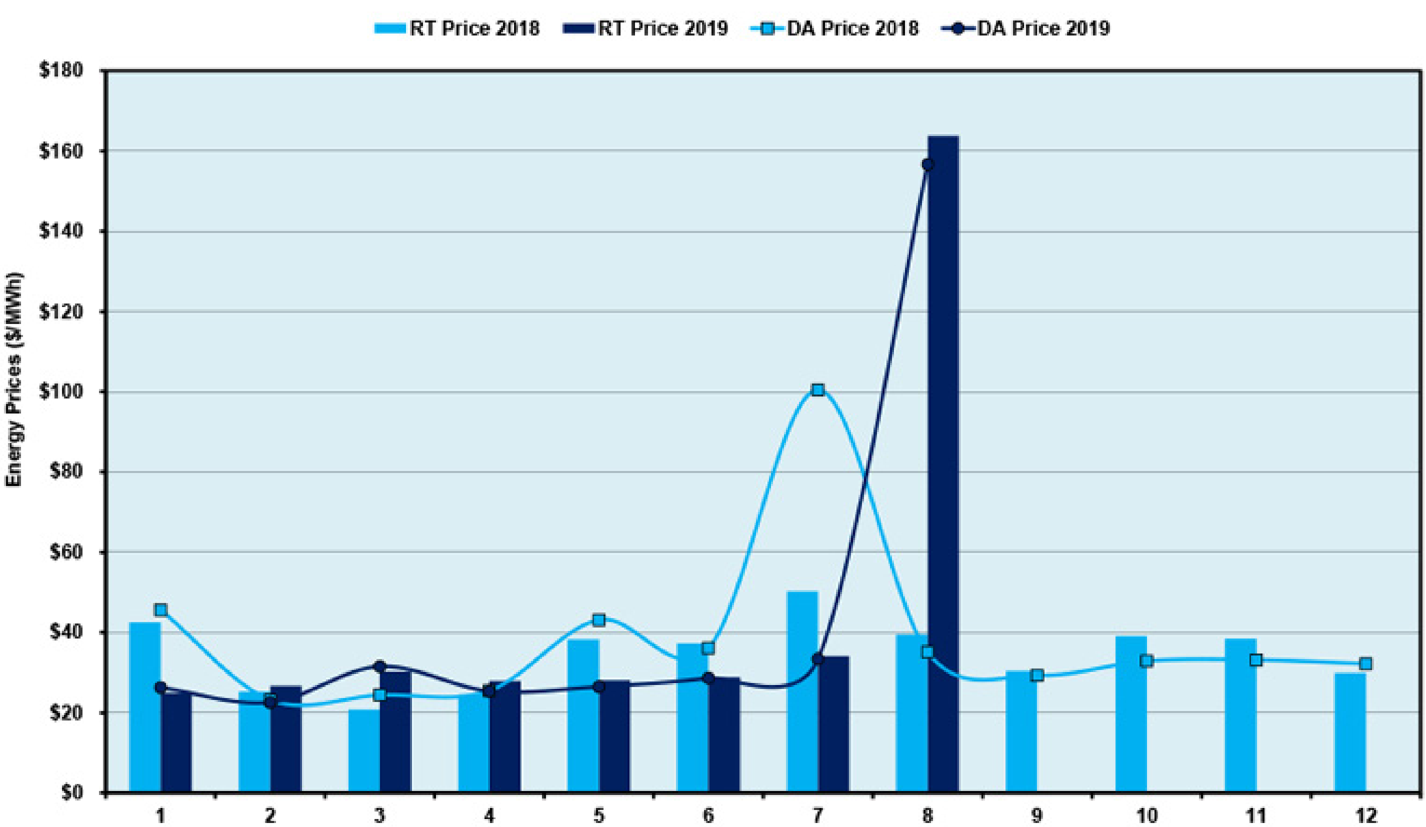
"Capacity markets procure a lot of reserves that aren't needed, and that costs a lot of money," he said. "Generators are asking us to intervene. ... To me, we're spending a lot of time arguing about whether we need to subsidize nuclear or coal. To me, that's an argument from a long time ago. What we need, with intermittent resources, is a lot of flexibility on the gird. We should incentivize and reward flexibility."

Tim Wang, a director with Filsinger Energy Partners, questioned whether energy markets will even remain viable in the future.

"Energy markets are based on 1990s technology and fuel costs. That is all changing," he said.

Wang said energy storage costs are dropping as dramatically as wind and solar costs, further reducing marginal costs.

"In the future, with 100% renewable energy markets, the marginal costs could be zero. There are no coal or gas heat rates. All that is gone ... so what does the future look like? Will the markets still be there?" ■



Scarcity is driving higher ERCOT prices. | *Potomac Economics*

FERC/Federal News

Chatterjee Coal Country Forum to Consider 'Energy Transition'

Continued from page 1

Association CEO Kelly Speakes-Backman and Deputy Energy Secretary Dan Brouillette.

"Launching the EnVision Forum in my home state of Kentucky, where we are seeing a wave of societal challenges due to the closure of coal plants and mines, was the logical first step for us to take," Chatterjee said in a *statement*.

"We want to start some new conversations with new voices and create relationships and understanding among the range of interests that are affected by this energy transition."

There will also be panels on the intersections between energy and telecommunications, water and the opioid epidemic ("Pain, Pills, and Police: The intersection of the energy industry and the opioid epidemic").

"The law enforcement community is grateful for Chairman Chatterjee's out-of-the-box thinking in also focusing this conference on the intersection of the opiate epidemic and the coal industry at both ends of our commonwealth," panel moderator Russell Coleman, U.S. attorney for the Western District of Kentucky, said in a statement.

Speaking to *RTO Insider* on Friday, Chatterjee said he has been "humbled and overwhelmed by how much interest there has been in this." He estimates that, not including press and support staff, about 170 people have confirmed they will attend so far.

The event will be held "throughout" Kroger Field, the University of Kentucky's 61,000-seat football stadium. Chatterjee said he has not yet done a site visit, but the stadium is home to the *Woodford Reserve Club*, used to host special events.

Chatterjee said the idea for the event took shape over the past six months. He said that as the industries that FERC regulates rapidly change, "the commission has clearly seen an increase in the visibility of its work," but "a lot of people aren't familiar with it."

"It's time people had a better idea of what FERC does," he said. The forum will also give the commission the opportunity to hear discussions it wouldn't normally be able to during its regular business hours, he said.

But Chatterjee also "liked the idea of getting out of Washington" and introducing stakeholders to Kentucky, a place that hasn't felt the benefits of the energy transition as much as others, he said.

Prior to joining FERC, Chatterjee, a Lexington native, was an adviser on energy policy to Senate Majority Leader Mitch McConnell (R-Ky.). But energy wasn't his first choice when coming to Capitol Hill: He originally wanted to work on health care policy, he said, as both his parents were professors and cancer researchers at UK. (He attended St. Lawrence University in upstate New York, as he couldn't stand the idea of taking classes from his parents and their friends, he said.)

It was only when working on energy issues on behalf of McConnell that, he said, he fully realized the importance of coal to Kentucky. "Coal wasn't just part of the economy; it's part of the cultural lifeblood of the state."

It's also a central part of politics there. McConnell, who faces re-election in 2020, has been *attacked* by his Democratic challenger, Amy McGrath, for not supporting legislation to strengthen coal miners' pensions or a fund that supports miners with black lung disease.

Just after he joined the commission in August 2017, Chatterjee said in FERC's "Open Access" *podcast* that as a Kentucky native, "I've seen firsthand throughout my life how important a contribution coal makes to an affordable and reliable electric system. ... As a nation, we need to ensure that coal, along with gas and renewables, continue to be a part of our diverse fuel mix."

A year later, after FERC unanimously rejected the Department of Energy's NOPR Notice of Proposed Rulemaking calling for price supports for coal and nuclear plants, Chatterjee talked about how former Chairman Kevin McIntyre had "helped me grow in my role as I made the transition from formerly partisan legislative aide to independent regulator." (See *Returning Chair Pledges to Protect FERC's Independence*.)

That hasn't prevented Chatterjee from being labeled "*McConnell's coal guy*," as Politico put it in a report that quoted numerous former commission staff members as saying he is more interested in politics than policy.

The inclusion of a panel on the opioid crisis had some FERC watchers scratching their heads.

"It appears from the content of this event that the chairman is [planning to run] for political office in Kentucky," said one FERC observer who agreed that Chatterjee appears more animated by politics than by many of his FERC duties.

University of Kentucky's Woodford Reserve Club | *University of Kentucky*

"This is a purely substantive event with serious and diverse technical content that is not political in any way whatsoever," Chatterjee said Monday when asked if any political ambitions in the state.

It's apparent at least that he did not shy away from the controversial. One panel is titled "All of the Above vs. Green New Deal: How States Balance Costs, Carbon and Communities" and will feature several state utility commissioners. Another is a "Conversation on Climate," to be moderated by Rich Powell, executive director of *ClearPath*, an organization that supports "conservative policies that accelerate clean energy innovation." Jason Bordoff, director of Columbia University's Center on Global Energy Policy, will be a panelist.

Tyson Slocum, director of Public Citizen's Energy Program, who has been highly critical of FERC, said he agreed to participate as a panelist on "Empowering 21st Century Energy Consumers with Technology" after receiving assurances he would be able to make his points that "FERC has to do a lot more to ensure the public and the public interest has a meaningful seat at the table" on commission issues and on RTO governance.

Public Citizen and other groups have been pushing since at least 2016 to have FERC provide public funding for interventions before the agency, as they say was required by the Public Utility Regulatory Policies Act. (See *Citizens Groups Seek Public Funding for FERC Interventions*.) ■

Rich Heidorn Jr. contributed to this report.

CAISO/West News

CPUC Opens Investigation of PG&E Bankruptcy Plan

Bondholders up Offer to Fire Victims

By Hudson Sangree

The California Public Utilities Commission opened a formal examination into Pacific Gas and Electric's Chapter 11 reorganization plan Thursday, as bondholders trying to take over the bankrupt utility upped the ante by offering wildfire victims $6 billion more than the utility has proposed.

The commission voted unanimously for an order instituting investigation (OII) that will consider how PG&E's plan to emerge from bankruptcy will affect ratepayers. The CPUC must approve any proposed plan for its reorganization.

"The commission is party to the Chapter 11 matter in the bankruptcy court and will continue to represent the interests of California in this matter," new CPUC President Marybel Batjer said from the dais. "The commission's focus remains solely on ensuring Northern Californians receive safe and reliable service at reasonable rates and consistent with achieving California's climate goals."

Among the CPUC's considerations are PG&E's compliance with AB 1054, a new law that lets the state's investor-owned utilities participate in a $21 billion fund to pay for fire damages. The caveat is that PG&E must satisfy the requirements of AB 1054 and emerge from bankruptcy by June 30, 2020, if it wants to benefit from the state's insurance-like fund. (See *Calif. Lawmakers Rush to Pass Utility Wildfire Aid*.)

The deadline has lent new urgency to reorganize the company, which faces billions of dollars in debts from the recent wildfires sparked by its equipment. Those fires included the November 2018 Camp Fire, the deadliest and most destructive in state history, and the Northern California wine country fires of October 2017. The expected liability for the fires drove PG&E to seek bankruptcy protection in January.

The commission said Thursday that the broader scope of its investigation would provide more opportunity for public input than the relatively limited scope of the bankruptcy proceedings.

"As much as we get criticized for being complicated and arcane, we are nothing compared to the bankruptcy court," Commissioner Liane Randolph said, prompting laughter. "So this really is the opportunity for parties with more diverse interests to participate in a somewhat more publicly accessible process."

Commissioner Clifford Rechtschaffen noted that the OII was familiar ground for the CPUC, which had to approve PG&E's bankruptcy reorganization plan following the California energy crisis of 2000/01. He said he was confident the commission could deal with the matter "expeditiously."

The CPUC will focus on the safety concerns that have plagued PG&E since the San Bruno gas pipeline explosion of 2008, which resulted in the commission's ongoing investigation into the utility's safety culture, Rechtschaffen said.

Bondholders Push Harder

Two blocks away from CPUC headquarters in San Francisco, in the U.S. Bankruptcy Court for the Northern District of California, a group of PG&E bondholders increased their offer to fire victims in a reorganization plan they want the court to adopt.

The plan by the Ad Hoc Committee of Senior Unsecured Noteholders would seize control of the utility from its current shareholders. It has asked bankruptcy Judge Dennis Montali, for a second time, to end PG&E's period of exclusivity, the time the company has to offer and solicit support for its own reorganization plan, unhampered by competing proposals. (See related story, *Lawyers Clash in PG&E Bankruptcy Hearing*.)

A hearing to consider that motion is scheduled for Oct. 7.

In a term sheet filed with the court Wednesday, the bondholders said they would invest $29.2 billion in PG&E in exchange for 59.3% of the company's common stock. Their terms also require PG&E to pay or recast billions of dollars in unsecured debt, which typically can be refuted in bankruptcy.

The term sheet lists more than $17.5 billion in unsecured notes among PG&E's debts.

The bondholders, led by hedge fund Elliott Management Corp., recently announced they had the support of fire victims after pledging to fund a trust of $13 billion to pay for wildfire damages. In the term sheet filed Wednesday, they upped that offer to $14.5 billion plus another $11 billion to pay subrogation claims held by insurers and others.

The California Public Utilities Commission's headquarters are in San Francisco's Civic Center district. | © RTO Insider

PG&E, in its latest Chapter 11 plan, allotted $8.4 billion for a fire-victim trust, though it could increase that amount.

The utility told Montali that it has about $14 billion in financial commitments from banks and investors to help pay for its bankruptcy plan.

PG&E's plan also includes $11 billion for subrogation claimants, who are now on the utility's side. Those claimants include Boston-based Baupost Group, another high-risk investor, that bought up a reported $3.3 billion in subrogation claims from insurance companies. Baupost is a major PG&E shareholder that bought the utility's stock when it was selling for $30 to $40/share instead of the roughly $10/share value currently.

PG&E's critics said Baupost bought the insurance claims for pennies on the dollar and is trying to profit from the utility's $11 billion payment plan, partly to make up for its stock losses.

PG&E asked Montali on Wednesday to extend its window of exclusivity from late November to late January. It filed a document in support of that move from John Boken, managing director of AlixPartners, a firm that's providing interim management services to PG&E during its bankruptcy.

Boken assured the court in his declaration that the company had made a good-faith effort to move forward with one of the biggest bankruptcies in U.S. history.

Given PG&E's size and the complexity of its bankruptcy, "I believe the debtors have made significant progress in the administration of these Chapter 11 cases," Boken told the judge. ■

CAISO/West News

Lawyers Clash in PG&E Bankruptcy Hearing

PG&E Treats Fire Victims as 'Irritant,' Lawyer Says

By Hudson Sangree

Lawyers in the Pacific Gas and Electric bankruptcy case argued for hours last week over competing reorganization plans and how much the utility owes to wildfire victims.

The attorneys shot insults at one another at times during the hearing in U.S. Bankruptcy Court for the Northern District of California, in San Francisco. An attorney for fire victims said the utility was treating those it had harmed as annoyances, while an attorney in PG&E's camp said the plaintiffs' lawyers had a "credibility problem."

The new level of testiness came as the case seemed to be moving toward its endgame.

Over the last several weeks, major parties in the bankruptcy divided into two camps, each with its own reorganization plan, and PG&E reached an $11 billion settlement with insurers. That left only one big question: How much will PG&E pay fire victims?

"It does look like some of the important building blocks of what could be a global consensual deal are beginning to fall into place," attorney Dennis Dunne, with law firm Milbank, told Judge Dennis Montali. Dunne, who represents the official committee of unsecured creditors, called the recent developments "stunning" with "parties that are willing to write substantial checks."

On Sept. 13, PG&E announced it had reached an $11 billion settlement with subrogation claimants — the insurers and other parties trying to recoup insurance payments to victims of wildfires sparked by PG&E equipment.

As the insurers locked arms with PG&E and its shareholders, wildfire victims teamed up with investors that hold more than $10 billion in bonds. It was a coup for bondholders, who offered a reorganization plan that would give PG&E billions of dollars in cash in exchange for a controlling stake in the utility.

The bondholders' plan would pay fire victims $13 billion and the subrogation claimants $11 billion. PG&E's plan, as it currently stands, would provide a capped trust of $8.4 billion for fire victims in addition to the $11 billion for subrogation claims. (See *Judge to hear PG&E Takeover Plan*.)

A National Guard soldier searches for remains after the Camp Fire in Paradise, Calif., killed 86 people in November 2018. | *California National Guard*

Montali said he'll decide whether to allow the bondholders to submit their reorganization plan, to formally compete with PG&E's proposal, at a hearing Oct. 7.

Cecily Dumas, a San Francisco bankruptcy attorney, said the fire victims she represents were upset, some to the point of tears, that PG&E appeared to be offering insurance companies more money and putting them ahead of people who had lost family members, homes and businesses in the wildfires.

"Regrettably we are in this place ... where the victims are lined up behind a creditor plan," Dumas told the judge. PG&E, she said, hadn't shown fire victims a draft of its reorganization plan or met with victims' lawyers even once.

"They are playing it like we are an irritant, like a rock in your shoe," Dumas said. "We are not an irritant. We are the communities you burned. We are the loved ones of those whose lives you took. We deserve respect. This is not a chess game."

In response to Dumas' comments, attorney Bruce Bennett, who represents PG&E equity holders, said, "There's a fundamental credibility problem with the lawyers involved for the wildfire plaintiffs."

Representatives for fire victims had said, early in the case, that they anticipated about 100,000 claims and uninsured liability of approximately $36 billion, Bennett said. Now they've agreed to settle for $13 billion in the bondholders' plan, and the number of claims may be far fewer than anticipated, he said.

"There's a problem starting with very high aggressive numbers that are divorced from the actual facts," he said.

He encouraged the judge to appoint a mediator to help sort out the issue of damages.

Montali noted a separate proceeding in federal court was intended to estimate the amount of wildfire damages PG&E faces. The judge's ruling in that "estimation proceeding" will be binding, though it would be made moot by a settlement agreement between PG&E and the wildfire victims, Montali said. (See *PG&E Bankruptcy Split into Three Parts*.) ■

CAISO/West News

Bonneville Power Signs Agreement with CAISO EIM

By Hudson Sangree

The Bonneville Power Administration signed an implementation agreement with CAISO's Western Energy Imbalance Market on Thursday, positioning a vast region of the Pacific Northwest, with its powerful hydroelectric dams and thousands of miles of transmission lines, to begin participating in the ISO's real-time market in 2022.

"We see BPA's participation in the Western EIM as the natural next step in a collaborative partnership that began many years ago to optimize transmission connections and boost reliability throughout the West," CAISO CEO Steve Berberich said in a *statement*. "BPA will provide exceptional benefits to the real-time energy market, as it leverages its robust and regionally strategic transmission system and energy resources."

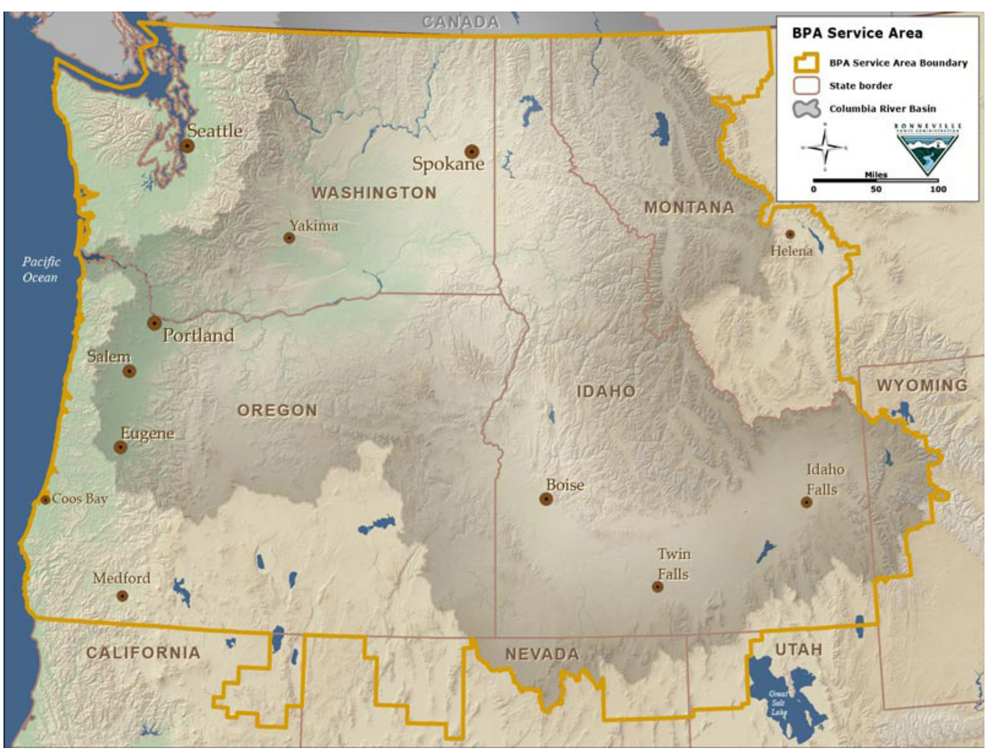
BPA would be the largest transmission owner and hydroelectric provider in the EIM. The federal power marketing administration owns and operates three-quarters of the high-voltage transmission lines in the Pacific Northwest, totaling about 15,000 circuit-miles. Its footprint occupies an area larger than the size of France, encompassing the sprawling drainage areas of the Columbia and Snake rivers.

The agency's assets include 31 hydroelectric projects, such as the 7,079-MW Grand Coulee Dam and the 2,614-MW Chief Joseph Dam. It supplies electricity to 143 electric utilities that serve millions of customers in Washington, Oregon, Idaho, Montana, California, Nevada, Utah and Wyoming.

The move also boosts CAISO's EIM in competition with SPP's nascent Western Energy Imbalance Service. (See *WAPA, Basin, Tri-State Sign up with SPP EIS*.)

While the implementation agreement is nonbinding, it commits BPA to paying a $1.8 million nonrefundable implementation fee, the first payment of up to $35 million in estimated start-up costs. BPA will not issue its final record of decision on becoming a member until late 2021, just months before it plans to join in March 2022. (See *BPA Marches Toward EIM Membership*.)

"This milestone was made possible by the collaboration and broad participation of our customers and constituents in the Northwest," BPA Administrator Elliot Mainzer said in a statement. "We've also benefited from a strong partnership with the CAISO that allowed us to carefully explore the value of the EIM for BPA and its customers, while addressing issues important to the region."



The Bonneville Power Administration's service area stretches across a vast area of the Pacific Northwest. | *BPA*

BPA said the EIM will allow it to more efficiently market its hydropower and manage transmission usage and congestion. The agency has touted the ability to use the EIM as a "non-wires" solution to address congestion and avoid new transmission builds while helping to identify areas of needed investment.

"Selling surplus energy and capacity in the Western markets is essential to keeping Bonneville's rates low," the agency said on its *website*. "BPA must adapt its business model as these markets change. Our analysis shows that joining the Western Energy Imbalance Market is one potential method to achieve this outcome."

In June, BPA kicked off a monthlong public comment process in hopes of signing an implementation agreement with the EIM in September. During a July meeting at BPA headquarters, BPA "preference" customers concerned about their inability to trade in the EIM's intra-hour market probed agency officials about short-term opportunities to purchase surplus hydropower before it's offered into the EIM. (See *Customers Probe BPA on EIM Impact*.) While those concerns remain unresolved, no BPA customers apparently opposed joining the EIM.

"We got 100% support for signing that agreement," Mainzer said at the Northwest & Intermountain Power Producers Coalition annual meeting in Union, Wash., on Sept. 9.

CAISO is evaluating adding an extended *day-ahead market* (EDAM) to the real-time EIM to increase its usefulness as a regional marketplace, and the BPA administrator said he believed the EDAM is needed to help move BPA's hydropower and other renewable resources across the West.

"It's not going be enough to sell all this stuff on a five-minute market," Mainzer said.

CAISO says its five-minute market has saved participants more than $736 million in the five years since it started.

The Balancing Area of Northern California (BANC) and the Western Area Power Administration recently said they will sign an implementation agreement with CAISO that would allow WAPA's Sierra Nevada region and BANC members Modesto Irrigation District, Redding Electric Utility and Roseville Electric Utility to

Continued on page 13

CPUC Adds RAMP Costs to Rate Case for 1st Time

By Hudson Sangree

The California Public Utilities Commission authorized costs for a new safety program as part of a utility's general rate case (GRC) for the first time Thursday, when it approved rate increases for San Diego Gas & Electric and Southern California Gas.

The unanimous approval of the utilities' three-year general rate case included costs associated with the CPUC's Risk Assessment Mitigation Phase (RAMP) program.

The "applicants are the first utilities to incorporate RAMP into their GRC filings, and these costs are being included in [their] respective revenue requirements for the first time in [test year] 2019," the CPUC said in its decision.

Both companies are owned by Sempra Energy.

The RAMP program is part of the CPUC's efforts to address disasters caused by the state's three big investor-owned utilities, such as the San Bruno gas pipeline explosion and recent wildfires. The program, and the related Safety Model Assessment Proceeding (S-MAP), require the IOUs to examine the risks they face and propose strategies to mitigate those risks, which the CPUC must then approve.

The utilities' RAMP reports would eventually be integrated into their GRCs every three years, the CPUC decided. The SDG&E/SoCal Gas rate case was the first time that happened.

"The SDG&E and SoCalGas RAMP proceeding is an opportunity for large California investor-owned utilities to describe their proposed mitigations for safety risks associated with the operation of their assets," the CPUC said on its *website*.

For SDG&E and SoCalGas, the rate-case *decision* filled nearly 800 pages, following a two-year review in which 20 parties intervened and 500 exhibits were entered into evidence, said Liane Randolph, the commissioner assigned to the rate case.

The result included a $1.99 billion revenue requirement for SDG&E's combined operations and $2.77 billion for SoCalGas in 2019, with adjustments allowed in 2020 and 2021. A typical residential customer will see an increase of $1.01/month (0.7%) for electric service and $4.50 to $5 (about 14%) a month for gas service, Randolph said.

"However, a large part of the increases represents costs for incremental safety-related programs and activities that are being added to the GRC for the first time as a result of the ... RAMP process," Randolph told her colleagues at Thursday's meeting. "The RAMP process requires SDG&E and SoCalGas to identify key safety risks and to propose programs that mitigate those risks."

Programs being approved address wildfires caused by utility equipment and catastrophic damage from pipeline failures. Among SDG&E's programs are 3D imaging that lets the utility assess the risk of pole failure because of winds and third-party attachments to poles, Randolph said. A gas leak survey process that uses electronic mapping is another example, she said.

RAMP costs are part of the PG&E's next *rate case*, which the CPUC plans to decide in early 2020. ■

Bonneville Power Signs Agreement with CAISO EIM

Continued from page 12

begin trading in the EIM in April 2021. The decision does not affect any other WAPA regions.

WAPA SN would be the first PMA to participate, potentially followed by BPA. The agreement represents the second phase of BANC's approach to incorporating its members into the EIM. Sacramento Municipal Utility District entered the market in April. (See *SMUD Goes Live in Western EIM*.)

Other current Western EIM participants include CAISO, PacifiCorp, NV Energy, Arizona Public Service, Puget Sound Energy, Portland General Electric, Idaho Power, Powerex and BANC (Phase 1). The Western EIM is slated to expand with the participation of Salt River Project and Seattle City Light in 2020; Los Angeles Department of Water and Power, NorthWestern Energy, Turlock Irrigation District, Public Service Company of New Mexico and BANC (Phase 2) in 2021; and Tucson Electric Power, Avista and Tacoma Power in 2022. ■

BPA's McNary Dam spills on the Columbia River on the border of eastern Oregon and Washington. | *U.S. Department of Energy*

ERCOT News

DOJ Weighs in on Texas ROFR Lawsuit

By Tom Kleckner

The U.S. Department of Justice on Sept. 20 filed a "statement of interest" with the federal district court hearing an appeal of a Texas law giving incumbent utilities the right of first refusal over transmission projects (1:19-cv-00626).

Assistant Attorney General Makan Delrahim and attorneys from the department's Antitrust Division sided with NextEra Energy that *Senate Bill 1938* violates the U.S. Constitution's dormant Commerce Clause, which prohibits states from "unduly" restricting interstate commerce or adopting "protectionist measures."

DOJ said SB 1938 places competition in Texas' deregulated retail electric market "at risk." It used as examples a competitive MISO project in southeast Texas recently awarded to NextEra Energy Transmission (NEET) Midwest and a pending application by NEET Southwest for a certificate of convenience and necessity in SPP's Northeast Texas footprint.

The department said the legislation puts competitive transmission's benefits "in jeopardy," with the "likely result" of higher electricity costs, and that SB 1938 "discriminates in favor of companies with a local physical presence."

The bill, passed into law in May, grants CCNs to build, own or operate new transmission facilities that interconnect with existing facilities "only to the owner of that existing facility." (See *Texas ROFR Bill Passes, Awaits Governor's Signature*.)

DOJ also said SB 1938 "diverges from national trends towards more competition that arose after FERC found in the 1990s that it is not in 'the economic self-interest of public utility transmission providers to expand the grid to permit access to competing sources of supply.'"

NextEra Energy Capital Holdings (NEECH) and four other NextEra transmission owner/developer entities in June filed a lawsuit calling for repeal of SB 1938 in the U.S. District Court for the Western District of Austin. The suit names Public Utility Commissioners DeAnn Walker, Arthur D'Andrea and Shelly Botkin as defendants. (See *NextEra Takes Texas to Court over ROFR Law*.)

The lawsuit calls for both declaratory relief to invalidate the law and injunctive relief to prevent the PUC from enforcing the law.

NextEra said it has standing because the law jeopardizes its Hartburg-Sabine Junction competitive project in southeast Texas and its acquisition of 30 miles of 138-kV facilities from Rayburn Country Electric Cooperative.

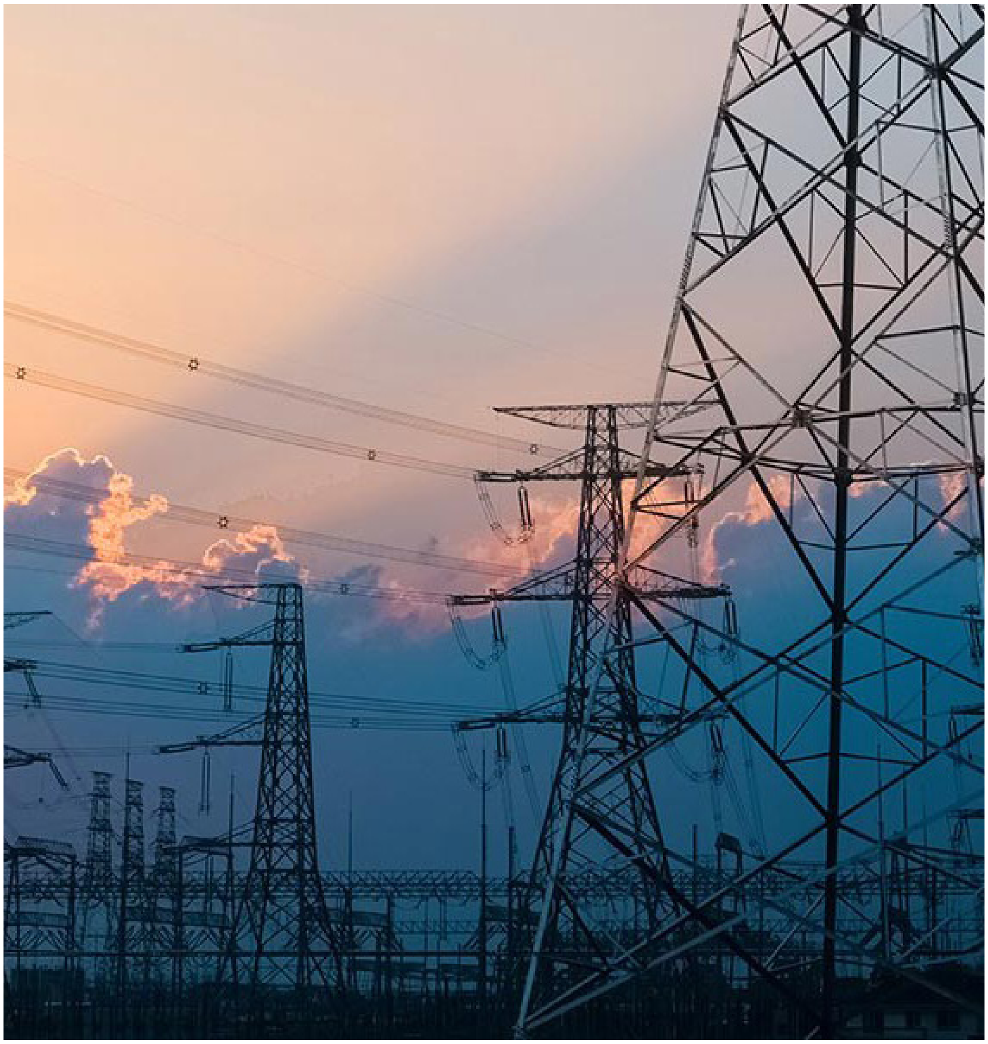
Texas Attorney General Ken Paxton was also named as a defendant, but he has since been dismissed from the proceeding.

The Texas Attorney General's Office in August argued for dismissal of NextEra's complaint, saying SB 1938 "is simply the codification of the long-time Texas (and successful) practice that the owners of existing transmission lines build out their existing lines from their endpoints."

SB 1938 is not protectionist, and NextEra does not state a claim under the dormant Commerce Clause, Paxton's office said. "NextEra has no vested contract rights, only an expectation, with respect to the transmission lines in question. And its rights were always subject to the imposition of new standards in the heavily regulated electric-utility industry."

An appeals court in August *granted* Entergy Texas, Southwestern Public Service and Texas Industrial Energy Consumers' motion to dismiss their appeal of a 2017 PUC order negating an incumbent utility's ROFR (03-18-00666-cv). The parties filed their request in July, arguing SB 1938 had rendered the case moot. (See *SPS, Entergy File to Pull ROFR Appeal*.)

A similar ROFR case is unfolding in Minnesota, with oral arguments scheduled for Oct. 16 in the 9th U.S. Circuit Court of Appeals. DOJ similarly joined the challenge against that state's ROFR law. (See *Justice Dept. Joins Challenge to Minn. ROFR Law* and *Courts Uphold Minn. ROFR, MISO Cost Allocation*.) ■



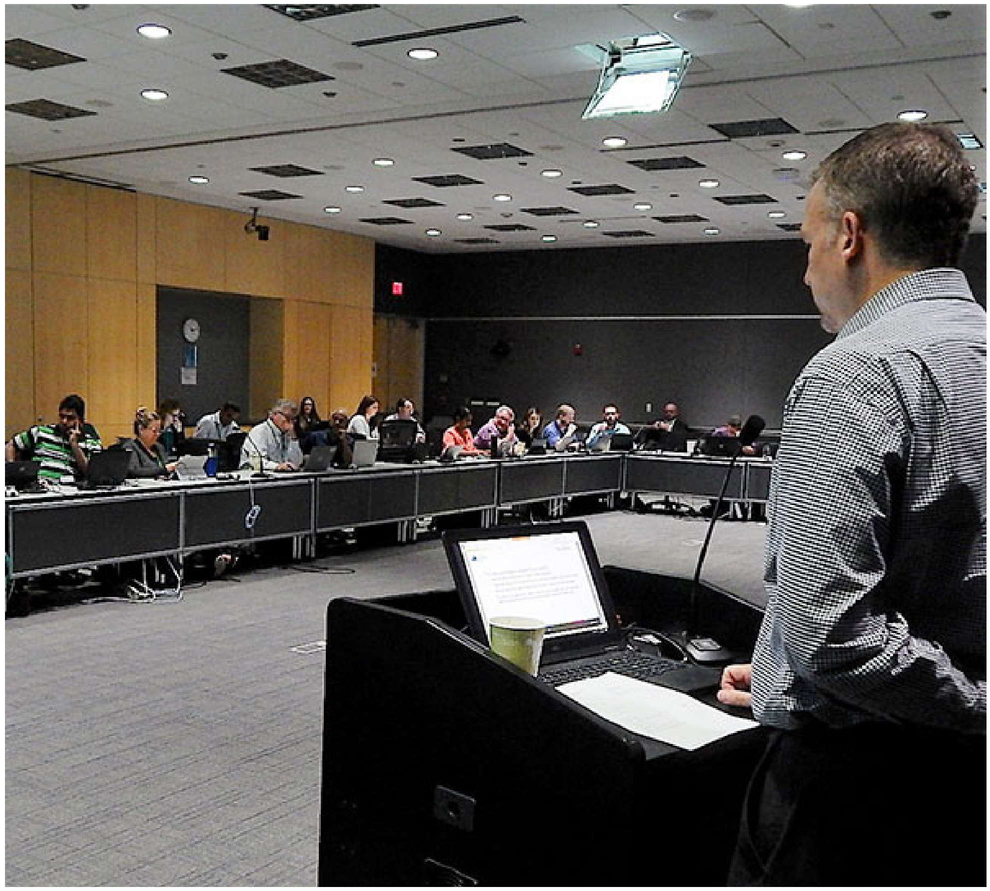
| Cherokee County Electric Cooperative Association

ERCOT News

RTOs Gather to Discuss Real-time Co-optimization

MISO, PJM, SPP Share Lessons Learned with ERCOT Task Force

By Tom Kleckner



ERCOT's Matt Mereness kicks off the lessons-learned session. | © *RTO Insider*

AUSTIN, Texas — Normally, Texas' electricity industry points to ERCOT's energy-only — and deregulated — market as a model for the rest of the country to follow.

Last week, however, ERCOT staffers and stakeholders gathered to hear advice from the RTOs that have already implemented real-time co-optimization (RTC) in their markets. MISO, PJM and SPP staff gave high-level overviews of their forward markets and lessons learned from their experience with the practice.

The Texas grid operator is just months into a multiyear effort to improve its market by adding RTC, a market tool that procures both energy and ancillary services (AS) every five minutes to find the most cost-effective solution for both requirements.

Gary Cate, SPP | © *RTO Insider*

Gary Cate, SPP's manager of market design, told members of the Real-Time Co-optimization Task Force gathered at ERCOT's headquarters that his RTO's implementation of RTC was "clean once we went there" with its integrated marketplace in 2014.

"[Our] real-time market doesn't have performance issues," Cate said, rapping the podium in front of him. "The day-ahead market did have commitment issues initially, with reg[ulation] up and reg down as separate products … but we didn't have a lot of issues from a co-optimization perspective. We did co-optimization after multiple RTOs did it, so we kind of learned from their missteps."

MISO added RTC to its market in 2009 at a cost of $75 million. Jeff Bladen, MISO's executive director of digital strategy, said the tool provides an annual return of at least $60 million through a more efficient commitment and dispatch of energy and reserves.

"Our fundamental belief is co-optimization for all our products is necessary to be as efficient as our customers expect us to be. The market is now compensating for availability and flexibility, not just energy," Bladen said. He noted the RTO plans to file a request with FERC to offer a short-term, 30-minute spinning reserve product.

MISO suggested ERCOT pay attention to ramp sharing, where energy and reserves share the same ramp capability. Bladen said the RTO observed frequent price spikes during parallel operations, which increased reliability risks because insufficient reserves were cleared. With ramp sharing, he said, reserve requirements are scaled up to account for the sharing.

ERCOT's Matt Mereness, who chairs the RTCTF, said he found the information beneficial for the team's current principle design phase, including the need to focus on "market education and technical details."

MISO, PJM and SPP operate capacity markets, designed to ensure reliability by requiring suppliers to have enough resources to meet customer demand and a reserve amount. ERCOT's energy-only market pays generators only when they provide power day-to-day, relying on scarcity pricing to incent additional generation.

'Grappling' with RTC

Bill Barnes, Reliant Energy | © *RTO Insider*

Reliant Energy's Bill Barnes said RTC will work well in ERCOT's market, pointing to the construction of demand curves as being the important difference.

"The energy-only market relies on the ASDC [ancillary services demand curve] to set scarcity prices to drive operational and investment decisions," he told *RTO Insider*. "The must-offer requirement in the other markets is due to resource adequacy requirements that don't exist in ERCOT."

Resmi Surendran, senior director of regulatory policy for Shell Energy, agreed with Barnes. She said the AS demand curve's design and the restrictions placed on AS offers could significantly affect the reserve margins the market can sustain.

ERCOT News

Capacity markets expect must-offers from resources with capacity obligations, "which seems reasonable as they are paid to be available," she said. She pointed out SPP and MISO were "very explicit" during their discussion that AS must-offers and near-zero offers for the services shouldn't be expected if the RTO values the AS product.

"They don't require resources that don't have capacity obligations to offer into the AS market, and their offer caps for these AS products are high," Surendran said. "AS markets are not a key revenue stream for the generators in those markets. In ERCOT, that is not the case. … How we design it could have an impact on the new type and amount of investments the market will attract."


Shams Siddiqi, Crescent Power | © *RTO Insider*

Shams Siddiqi, who has been involved in much of ERCOT's market design and is now president of consulting firm Crescent Power, has freely offered his expertise to the RTC task force. He said the tool will be more efficient in ERCOT's nodal market, where all AS-capable resources are required to offer or let the system create proxy offers.

ERCOT's must-offer requirement and reduced risk to selling AS under co-optimization will likely reduce AS prices, he said.

"Even if [ERCOT's] proxy AS offers are set to [$0], when the resource does not submit an offer [under RTC], it's unlikely that AS clearing prices will be $0, as AS clearing prices always take into account opportunity cost," Siddiqi said. "Unlike what's being proposed by ERCOT, other ISOs substitute higher-value AS capacity for lower-value AS capacity and maintain the substituted AS capacity as the higher-value service. This … results in higher level of reliability, making the ASDC continuous so that additional higher-value products always have value greater than or equal to lower-value AS service, and ensures higher or equal clearing price for higher-value AS compared to lower-value AS."

Barnes said stakeholders are "grappling" with how to set AS proxy offers for RTC. "The pricing of AS in other markets with RTC helps inform our decision," he said.

TAC Endorses 2 More Key Principles

The RTCTF also received endorsement last week of two additional key principles (KPs) from ERCOT's Technical Advisory Committee. (See *ERCOT Technical Advisory Comm. Briefs: Sept. 25, 2019*.)

The latest KPs are:

- KP 1.1: Replaces the operating reserve demand curve's adders with ASDCs to determine market-clearing capacity prices for AS products, while continuing to adjust for ERCOT's defined out-of-market actions to maintain reliability.
- KP 1.2: Evaluates the values of and interaction between the systemwide offer cap, value of lost load and power balance penalty price as part of RTC's implementation. The principle also sets parameters for the values.

The KPs will be sent to the ERCOT Board of Directors, which will now "consider," rather than "approve," the principles as a result of a tweak to the group's scope. Following the KPs' consideration, staff will draft and sponsor the necessary revision requests, according to the protocols.

The task force plans to consider 19 more KPs during its Oct. 9 meeting.

The TAC also reaffirmed Bryan Sams as the task force's vice chair. Sams recently left Lone Star Transmission for a position with Calpine as director of government and regulatory affairs. ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

TAC Approves Task Force to Study Battery Energy Storage

AUSTIN, Texas — ERCOT stakeholders approved the creation of a battery energy storage task force as the grid operator steps up its efforts to accommodate the resource type.

Staff told the Technical Advisory Committee on Wednesday that ERCOT is "shifting gears" and dedicating full-time resources to integrate energy storage in its systems. Staff conducted an energy-storage workshop in April but have done little publicly since.

"We need a more focused and centralized discussion," said ERCOT's Sandip Sharma, who will chair the Battery Energy Storage Task Force (BESTF). "Creating a formal task force structure would allow us to better share information with stakeholders."

Sandip Sharma, ERCOT | © *RTO Insider*

The *task force* will hold its first meeting on Oct. 18, when it will finalize a scope document and elect a stakeholder as vice chair. The group will report to the TAC, which will be asked to endorse any recommendations it makes.

The ERCOT Technical Advisory Committee meets Sept. 25. | © *RTO Insider*

Congestion in Permian Basin an Issue

Transmission congestion will remain an issue in the Permian Basin through 2020, staff told members, requiring ERCOT to request relief from the state's environmental regulator for increased generation emissions.

The Texas Commission on Environmental Quality obliged, granting "enforcement discretion" through 2019 for resources needed to resolve congestion in West Texas. A *market notice* detailing the action was distributed following the TAC meeting.

The commission said it would exercise its discretion in evaluating Luminant's Permian resources' compliance with air-permit limits "when they are needed to address certain ERCOT-declared transmission emergencies."

Luminant will only be subject to enforcement discretion when ERCOT declares a transmission emergency and commits one or more of its Permian units through a reliability unit commitment. The units are approaching their 2019 emissions limitations but are the only resources with shift factors sufficient enough to help security-constrained economic dispatch resolve the constraints.

ERCOT told the commission that the basin's substantial growth in petroleum-related load has resulted in "occasional limit exceedances" on the region's import paths. Transmission additions to relieve the congestion will not be completed until late 2020 and early 2021, staff said.

Staff Issue Guidance on D-side Resources

Staff also previewed a *market notice* describing "intended practices" to interconnect and operate distribution generation resources (DGRs) that participate in ancillary services or economic dispatch.

DGRs present "certain operational concerns" not yet addressed in ERCOT's rules, the grid operator said. It said it is concerned that the increasing numbers of DGR interconnection proposals "could create reliability risks if sufficient numbers of DGRs begin to interconnect."

ERCOT said it is developing rule revisions to resolve the issues and expects to submit the revision requests "in the near future." Until the rules are implemented, it said, DGRs should either operate under restrictions or be prohibited from interconnection.

"The most prudent policy at this point is to allow existing DGRs to continue operating and to allow those entities that can demonstrate substantial investment in one or more DGRs to pursue development of those DGRs, but

ERCOT News

only on the condition that each such existing or proposed DGR complies with certain specified conditions regarding interconnection and operation," ERCOT said.

Members Approve 23 Revision Requests

The committee cleared a two-month backlog of revision requests after rejecting a motion to table a system change request (SCR) to give transmission operators access to ERCOT's GridGeo application. The browser-based tool will provide better situational awareness of the transmission grid and is meant to replace the grid operator's Macomber Map. (See *ERCOT, SPP Collaborate to Improve Visualization Tool*.)

Emily Jolly, LCRA | *© RTO Insider*

Lower Colorado River Authority's Emily Jolly asked that *SCR804* be tabled to give stakeholders time to see whether the app could be scaled up for the greater market's use. "Real-time weather information, seeing what ERCOT does … that could really be helpful," she said.

ERCOT's Dan Woodfin explains the GridGeo application. | *© RTO Insider*

ERCOT Senior Director of System Operations Dan Woodfin said GridGeo contains integrated generation data. To open it up to market participants beyond transmission operators would require different software, he said, and increase its estimated $400,000 to $600,000 cost.

"I'm not sure it warrants holding up what the transmission operators need," Woodfin said.

The motion to table failed by a 9-13 vote, with eight members abstaining. The SCR passed by a voice vote, with LCRA abstaining.

The TAC unanimously endorsed 15 Nodal Protocol revision requests (NPRRs), two changes to the Nodal Operating Guide (NOGRR), single revisions to the Planning Guide (PGRR) and Retail Market Guide (RMGRR), a system-change request, a change to the Settlement Metering Operating Guide (SMOGRR) and two Verifiable Cost Manual updates (VCMRR):

- *NPRR918*: Clarifies and updates hourly validation rules for the non-opt-in entity load forecast related to the submission of point-to-point obligations.
- *NPRR930*: Requires staff to use an outage-adjustment evaluation process to delay accepted or approved outages after issuing an advance action notice, providing time for qualified scheduling entities to adjust their outage plans. The NPRR sets an offer floor of $4,500/MWh for resources in making them whole for following ERCOT's instructions.
- *NPRR936*: Changes the congestion revenue rights (CRR) auction's transaction limit to the counter-party level from that of the CRR account holder.
- *NPRR939*: Replaces ERCOT's practice of creating two groups of load resources, other than controllable resources providing responsive reserve service (RRS), into groups of 500 MW each to provide up to 60% of the system's RRS requirement and up to 150% of their RRS ancillary service responsibility toward physical responsive capability (PRC). The change allows ERCOT to maintain at least 500 MW of PRC from generation resources when releasing RRS capacity to SCED.
- *NPRR940*: Removes from the protocols *NPRR664*'s gray-boxed language that introduces a fuel index price for resources.
- *NPRR948*: Incorporates changes in the American National Standards Institute standards; increases the test schedule for coupling capacity voltage transformers (CCVTs) tested in the last quarter of a year and removes references to fiber-optic current transformers.
- *NPRR950*: Prohibits any switchable generation resource contracted to provide black start service from generating in any control area other than ERCOT's.
- *NPRR951*: Expands the network security analysis active constraints report and the network security analysis inactive constraints report to include megavolt-ampere flows and limits.
- *NPRR952*: Fully replaces the Houston Ship Channel with Katy Hub as the reference for the natural gas fuel index price in ERCOT's systems.
- *NPRR954*: Allows transmission and distribution service providers or load-serving entities to opt out of Texas standard electronic transaction 867 data for electric service identifiers with ERCOT-polled settlement meters.
- *NPRR958*: Modifies the wind and solar capacity calculations used in ERCOT's Capacity, Demand and Reserves (CDR) report and better aligns the two calculations.
- *NPRR959*: Splits the CDR's existing non-coastal wind region into a Panhandle region and an "other" region.
- *NPRR960*: Revises *NPRR863*'s gray-boxed language to implement the Board of Directors-approved phasing approach for the NPRR. Also corrects resource status references within the gray-boxed language.
- *NPRR961*: Aligns the protocols with changes proposed in NOGRR194.
- *NPRR962*: Requires ERCOT to publish hourly the approved DC tie schedule for the following seven days.
- *NOGRR191*: Paired with NPRR939, allows ERCOT to manually deploy load resources providing RRS to maintain at least 500 MW of physical responsive capability reserves while maintaining stable grid frequency for smaller disturbances.
- *NOGRR194*: Clarifies and relocates to the Nodal Operating Guide black start training attendance requirements, originally located in the Nodal Protocols.
- *PGRR072*: Allows staff to collaborate with stakeholders in setting a resource not yet subject to a notification of suspension of operations to "out of service" in the regional transmission plan and geomagnetic disturbance vulnerability assessment base cases, provided the resource's entity notifies ERCOT of its intent to retire or mothball the resource or makes its intent public.
- *RMGRR161*: Aligns the guide's language with state regulations for providers of last resort by specifying market notices' required contents in notifying market participants of a mass transition.
- *SCR803*: Adds to the wind-integration report a new graphical dashboard showing actual and forecasted solar production and creates new solar-integration reports.
- *SMOGRR022*: Removes from the guide references to fiber-optic instrument transformers.
- *VCMRR023*: Aligns the manual's language with NPRR940's removal of grey-boxed language.
- *VCMRR024*: Clarifies that auxiliary equipment using power from third-party service providers is recoverable as a variable cost, rendering moot the requirement to include start-up and minimum energy fuel consumption. ■

— Tom Kleckner

ERCOT News

Texas PUC Briefs

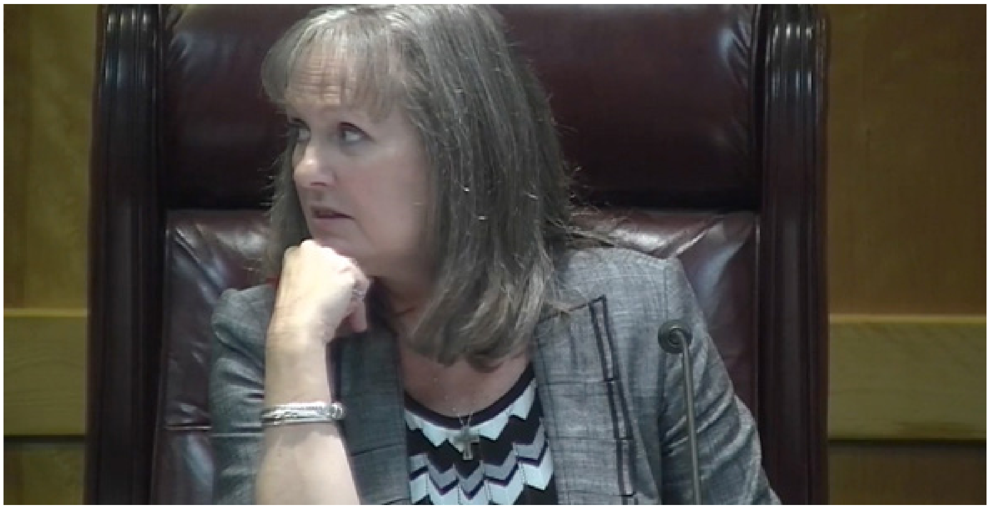
Commission Approves 1 of 2 Lubbock Projects

Texas regulators last week formally approved one of two transmission projects necessary to integrate much of the city of Lubbock's load into ERCOT.

The Public Utility Commission *signed off* on a certificate of convenience and necessity (CCN) during its open meeting Thursday, granting Sharyland Utilities and Lubbock's joint application for a 58-mile, $90 million 345-kV link between substations in Ogallala and Abernathy. Substation improvements will increase the total cost to nearly $100 million (*48625*).

The commission also heard oral arguments from two landowners opposing the path of the second 345-kV project, a 33-mile line from Abernathy to Wadsworth projected to cost about $74 million (*48668*).

The PUC will vote on the second CCN during its Oct. 11 open meeting. Chair DeAnn Walker suggested neither landowner — one of whom said he was a 101-year-old World War II veteran — needed to again make the long trip from Lubbock.

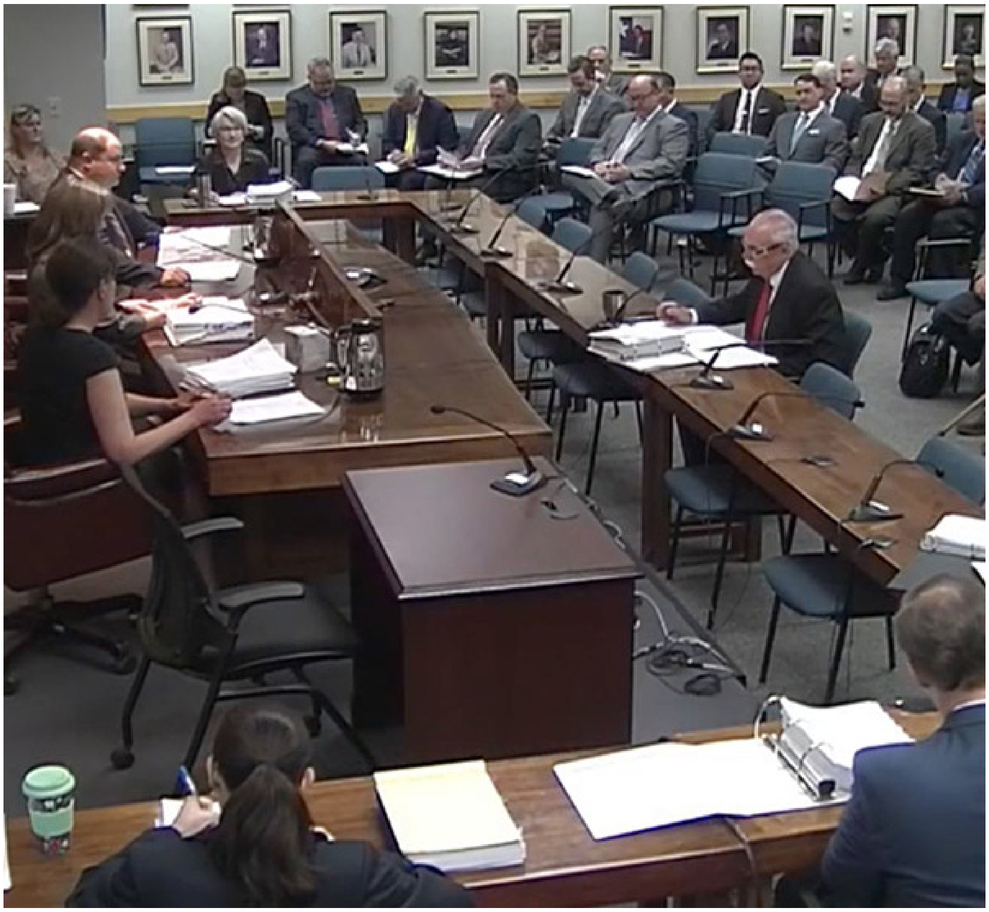


PUC Chair DeAnn Walker

"My daughters went to [Texas] Tech [in Lubbock], so I know what that drive's like," Walker said.

The CCNs are needed to move 470 MW of the city of Lubbock's load from SPP to ERCOT. (See "LP&L Lines for ERCOT Integration near Final Approval," *Texas PUC Briefs: Sept. 12, 2019*.)

Oncor will be responsible for the projects' construction before turning them over to Lubbock Power & Light, the city's municipal utility. Both lines are scheduled to be energized by June 2021, meeting LP&L's target date to join ERCOT.



The Texas PUC holds its open meeting Sept. 26.

Commission Approves Rate Recovery, $328K in Fees

In other business, the commission approved $110,600 in administrative penalties:

- Retailer Quest Distributors was docked $20,000 for collecting deposits without informing the commission and without adequate customer protections (*49576*).
- Utility AEP Texas settled for $69,000 (*49725*) and Entergy Texas settled for $21,600 (*49829*) in penalties regarding annual service quality.

The PUC approved El Paso Electric's requests for a distribution cost recovery factor, based on an annual Texas retail revenue requirement of almost $7.8 million (*49395*), and to implement an interim fuel refund of almost $19.2 million (*49482*). It also agreed to requests by Southwestern Public Service (*49495*) and Oncor (*49594*) to adjust their energy efficiency cost recovery factors. ■

— Tom Kleckner

ISO-NE News

FCA 13 Results Stand Without FERC Quorum

By Rich Heidorn Jr.

The results of ISO-NE's Forward Capacity Auction 13 became effective "by operation of law" Sept. 24 because FERC was unable to muster a quorum following the departure of Commissioner Cheryl LaFleur and the recusal of Commissioner Richard Glick.

The commission issued a notice on the action Sept. 25 (*ER19-1166*), and Chairman Neil Chatterjee and Commissioner Bernard McNamee issued a *joint statement* Friday saying that they would have voted to accept the results despite multiple protests.

The auction for June 2022 through May 2023 produced a clearing price of $3.80/kW-month, well below FCA 12's $4.63/kW-month and the RTO's lowest price in six years. It was the first auction run under the Competitive Auctions with Sponsored Policy Resources (CASPR) rules, which established a secondary substitution auction in which new generation resources could assume the obligations of resources that retire in the same commitment period. The substitution auction had a $0 clearing price, and no demand bids below that price cleared. (See *ISO-NE Completes FCA 13 Despite Controversy*.)

ISO-NE filed the results on Feb. 28. The results became effective when the commission failed to act within the 60-day deadline for filings under Federal Power Act Section 205. FERC said the clock began on July 26, when ISO-NE responded to the second of two FERC deficiency notices.

Glick, a former *lobbyist* for Avangrid, *said* he recused himself because the Vineyard Wind offshore project, a joint venture between Copenhagen Infrastructure Partners and Avangrid Renewables, filed a protest in the docket. (See *Glick Recusal May Mean No MOPR Ruling Before December*.)

LaFleur, who began abstaining from ISO-NE orders before leaving the commission at the end of August, joined the RTO's Board of Directors on Sept. 13. (See *LaFleur Elected to ISO-NE Board*.)

Chatterjee and McNamee said they would have upheld the auction results as just and reasonable, dismissing multiple protests as outside the scope of the proceeding or collateral attacks on past commission orders. They rejected arguments by Calpine, which said market design defects suppressed prices, and Public Citizen, which said consumers were overcharged in the substitution auction because only 10% of the supply offers cleared.

Waiver Request

Chatterjee and McNamee said they also would have voted to grant ISO-NE's request for a waiver from a rule requiring it to grant access to confidential information to parties that sign nondisclosure agreements. The RTO made the request so it wouldn't have to disclose resource-specific cost data submitted by the *Killingly Energy Center*, a 650-MW natural gas-fired generator slated to begin operations in Connecticut in 2022.

The commissioners acknowledged that FERC has "recognized both that parties have an interest in protecting the confidentiality of their data and that they must be permitted to participate meaningfully in proceedings." They said they had sought to allow both by requiring NDAs to access the confidential material. "But the commission has also recognized that it is inappropriate to disclose confidential material that can create adverse impacts to competition, even under a nondisclosure agreement," they wrote. "Specifically, in the FCA 8 order and 2017 waiver order, the commission ruled that release of resource-specific privileged information was inappropriate because that information would remain sensitive beyond the FCAs in question and could harm the competitiveness of FCAs going forward."

Chatterjee and McNamee also said they would have rejected the argument of a group of capacity suppliers (Cogentrix Energy Power Management, Great River Hydro, NRG Power Marketing and Vistra Energy) who challenged the ISO-NE Internal Market Monitor's unit-specific offer floor price for Killingly. They said it must have been at or below $3.79/kW-month — less than half the $8.19/kW-month default offer floor applicable to Killingly.

"We would have found that Killingly was appropriately mitigated," the commissioners wrote. "Based on an evaluation of the data submitted in the deficiency response in this docket, we believe that the IMM complied with its responsibilities as outlined in the Tariff. For example, we would have found that through its deficiency response, ISO-NE demonstrated that its review was not focused solely on whether Killingly received out-of-market revenues but rather that the IMM scrutinized all aspects of Killingly's offer to ensure they were consistent with prevailing market conditions, including all relevant cost components and revenue assumptions that support Killingly's offer."

Vineyard Wind MOPR

Also rejected were arguments by Vineyard Wind, Massachusetts Attorney General Maura Healey, Public Citizen and "Clean Energy Advocates" — Acadia Center, Conservation Law Foundation and the Sierra Club — that the auction resulted in unjust and unreasonable rates because Vineyard Wind was not exempted from the minimum offer price rule (MOPR) as a renewable technology resource (RTR).

The deadline to qualify as an RTR was Oct. 2, 2018. It wasn't until Jan. 29, 2019 — six days before the auction was conducted — that the commission accepted revisions to the Tariff allowing offshore wind resources to qualify as RTRs.

The commission never acted on Vineyard Wind's request for a Tariff waiver to participate in FCA 13. The request remains pending.

Clean Energy Advocates and Public Citizen complained that Vineyard Wind's exclusion as an RTR showed the substitution auction failed to accommodate state policies and will be an inadequate substitute once the RTR exemption is phased out.

"With respect to the substitution auction, the commission previously found that the substitution auction construct and gradual phase-out of the renewable technology resource exemption struck a just and reasonable balance between the competing objectives of maintaining competitive capacity market prices and accommodating state policy interests," Chatterjee and McNamee wrote. "The commission added that the substitution auction is not rendered unjust and unreasonable simply because it does not guarantee that state-sponsored resources will obtain capacity supply obligations." ■

Killingly Energy Center | *Killingly Energy Center*

ISO-NE News

Supply Side not Buying ISO-NE's ICR Numbers

By Rich Heidorn Jr.

NEPOOL's Reliability Committee on Wednesday rejected ISO-NE's proposed installed capacity requirement (ICR) calculations, with unanimous opposition from the Generation and Supplier sectors.

Needing a 60% majority to recommend them to the Participants Committee, the ICR values including and excluding Mystic Units 8 and 9 *failed* with only 49.65% support.

With the Generation and Supplier sectors unanimously opposed and the Transmission and Publicly Owned sectors unanimously in support, the vote hinged on a split in the Alternative Resources sector (8.71% in favor, 11.78% opposed). The End User sector lacked a quorum and was reported 0.98% in favor and 0% opposed.

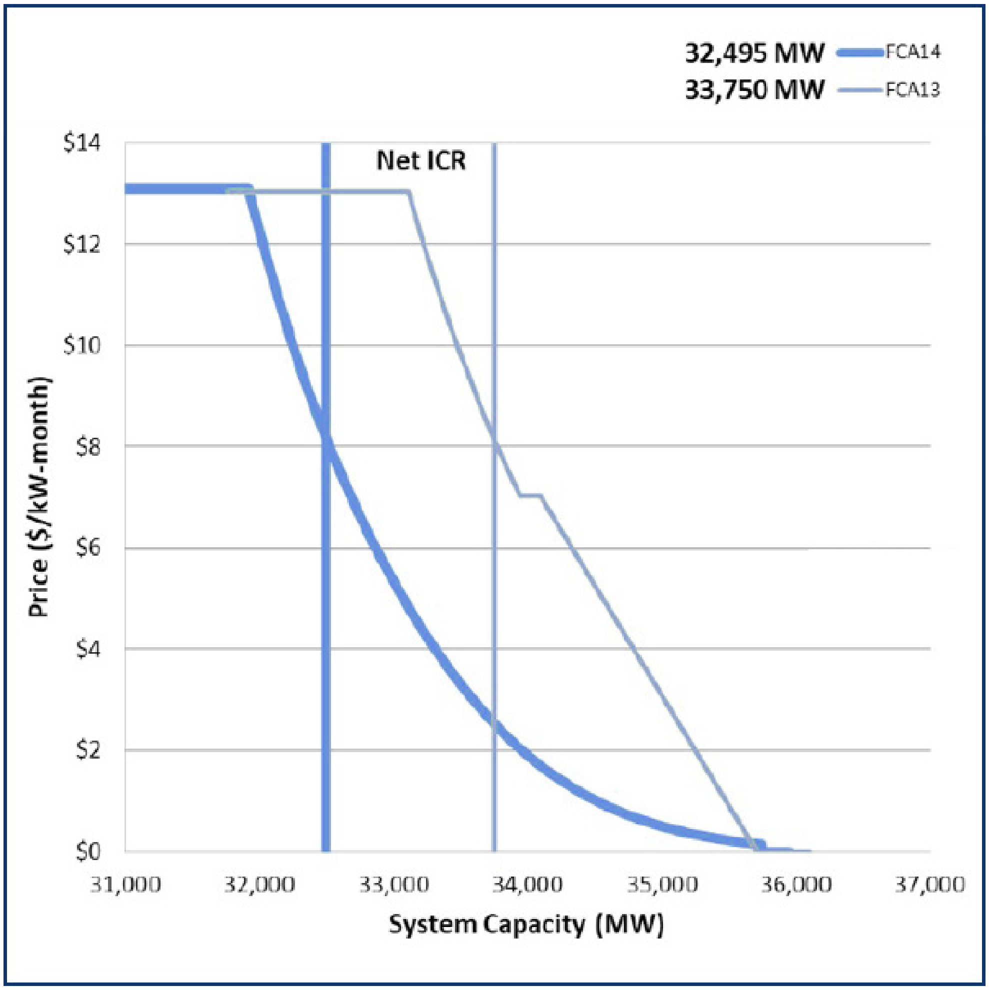
Excluding Mystic 8 and 9, ISO-NE is proposing a net ICR of 32,495 MW for Forward Capacity Auction 14 (2023/24), a reduction of 1,255 MW from FCA 13.

The committee did approve a 941-MW value for the Hydro-Québec interconnection capability credit (HQICC) for FCA 14 including the capacity associated with Mystic, and a 943-MW HQICC excluding it.

NEPOOL rules prohibit *RTO Insider* from quoting stakeholders' comments during the meeting. However, Bruce Anderson, vice president of market and regulatory affairs for the New England Power Generators Association, explained the generators' objections after the meeting. He said the reduced net ICR from FCA 13 "will undoubtedly put downward pressure on prices if accepted by FERC.

"NEPGA has raised a number of concerns with how the ISO modified its load forecasting methodology, which drove the decrease in NICR, including that it was done based in part on only a handful of days in summer 2018. We also believe that ISO-NE may not properly recognize that the peak-load hour is moving farther out due to solar penetration, and thus there may be actual less peak load shaving coming from the behind-the-meter solar than is shown in the load forecast," Anderson said in an email.

"In addition, ISO-NE has changed the load forecast methodology for purposes of calculating demand (the NICR) but not for purposes of calculating the cost of new entry (for which the load forecast is a significant variable). This inconsistent application of the change in load forecast methodology will cause the FCA to price capacity below its economic price."



The system demand curve shows an installed capacity requirement (ICR) of 32,495 MW for Forward Capacity Auction 14 (excluding Mystic 8 and 9), a reduction of 1,255 MW from FCA 13. | *ISO-NE*

Other stakeholders who criticized the RTO's calculations declined, or did not respond to, requests for comment.

"Developing the installed capacity requirement is a complex calculation involving many factors. The ISO develops the ICR according to national and regional power system reliability standards and requirements," ISO-NE spokeswoman Marcia Blomberg responded. "For stakeholders, there may be other considerations."

Opposition in 2018

It is at least the second year in a row that ISO-NE has faced opposition to its ICR calculations.

Last September, the committee *approved* an ICR value of 34,719 MW without Clear River Unit 1 for FCA 13, with more than 65.% support. But the RTO's 34,739-MW ICR with Clear River failed with only 50.01% support. In October, the Participants Committee voted *likewise* on the two values.

In January, FERC approved the 34,719-MW ICR after accepting the termination of Clear River's capacity supply obligation for 2021/22 (*ER19-291*).

FERC approved the ICR values over protests from NEPGA, FirstLight Power Resources and the New England States Committee on Electricity (NESCOE).

NESCOE complained that the filing by ISO-NE and NEPOOL failed to justify increasing system reserves to 700 MW from 200 MW, the level it had been at since 1980. NESCOE contended that ISO-NE was trying to justify its

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ICR value rather than determining the amount needed to support resource adequacy.

FERC defended the 700-MW reserve level as "a matter of engineering judgment." It noted that the system's peak load had nearly doubled since 1980 from about 15,000 MW to 28,000 MW today. The single largest contingencies in 1980 were two nuclear units of 800 to 900 MW each. "Today, New England can experience a single credible contingency of up to 2,000 MW associated with the Phase II interconnection with Hydro-Québec and three other large credible contingencies ranging between 1,250 [and] 1,650 MW each," FERC said.

FirstLight and NEPGA objected that the ICR-related values used in ISO-NE's ICR study are based on lower outage rates and higher tie benefit assumptions than those used in the RTO's fuel security study.

The commission said the generators' request to calculate ICR using the assumptions from the fuel security study would violate the Tariff.

"These two study processes are distinct and seek to achieve different objectives," the commission said. "While ISO-NE uses the ICR-related values to address an installed capacity problem, it uses the fuel security study to address a different problem: whether capacity procured in the Forward Capacity Market has sufficient fuel necessary to produce energy needed to meet demand and maintain required operating reserves. That is, a region may have sufficient installed capacity but insufficient fuel to produce energy from that capacity."

FCA 14 vs. 13

The new ICR values show a 1,065-MW reduction in the load forecast from FCA 13, including a 965-MW drop in the gross load forecast and a 105-MW reduction from updated estimates for behind-the-meter PV generation. The load also was affected by changes to the load forecast methodology, including the addition of a second weather variable (cooling degree days), the separation of the July and August peak load model, and the shortening of the historical weather period from 40 to 25 years.

Also reducing the ICR were improvements to system outage rates.

Those reductions were partially offset by a reduction in tie benefits (+70 MW) and the load relief assumed obtainable from implementing a 5% voltage reduction (+150 MW).

Other Action

In other action Wednesday, the Reliability Committee approved a number of projects, including Exelon Generation's plan to replace the excitation controllers and automatic voltage regulators (AVRs) at Mystic 8 and 9. The company will install ABB UNITROL Static Excitation Systems at each generator to provide excitation current to the exciters and replace the existing AVRs. They are expected to be in service in October.

Members also approved revisions to:

- Operating Procedure 19 to allow adjustments to phase-shifting transformers or reactive flow to maintain system reliability.
- the reactive capability audit request form to clarify the types of tests that can be selected on the form.
- Planning Procedure 10 to delete provisions related to interconnection service adjustments (Sections 7.7 and 7.8), which are being moved to a new section in the Open Access Transmission Tariff. The change won't take effect until FERC approves the Tariff amendment.
- Sections I.2.2 and III.12.6 of the Tariff to allow the inclusion of competitively developed transmission solutions into the FCM network model. ■

	ICR Values (MW) 2023/24		
	Including Mystic 8 & 9	Excluding Mystic 8 & 9	Difference
Installed Capacity Requirement	33,431	33,438	-7
Net Installed Capacity Requirement	32,490	32,495	-5
Southeast New England Local Sourcing Requirement	9,757	9,560	197
Maine Maximum Capacity Limit	4,020	3,950	70
Northern New England Maximum Capacity Limit	8,445	8,375	70

| *ISO-NE*

ISO-NE News

ISO-NE IDs $8.7M Tx Fix for Boston Area

National Grid to Install Reactor, Breaker

By Rich Heidorn Jr.

ISO-NE has identified a 160-MVAR reactor at National Grid's Golden Hills 345-kV substation in Saugus, Mass., as a key part of its solution to Boston's 2028 needs, the RTO's Kaushal Kumar told the Planning Advisory Committee on Thursday. The reactor, at an estimated cost of $5.47 million, is intended to correct high-voltage violations found at minimum load levels.

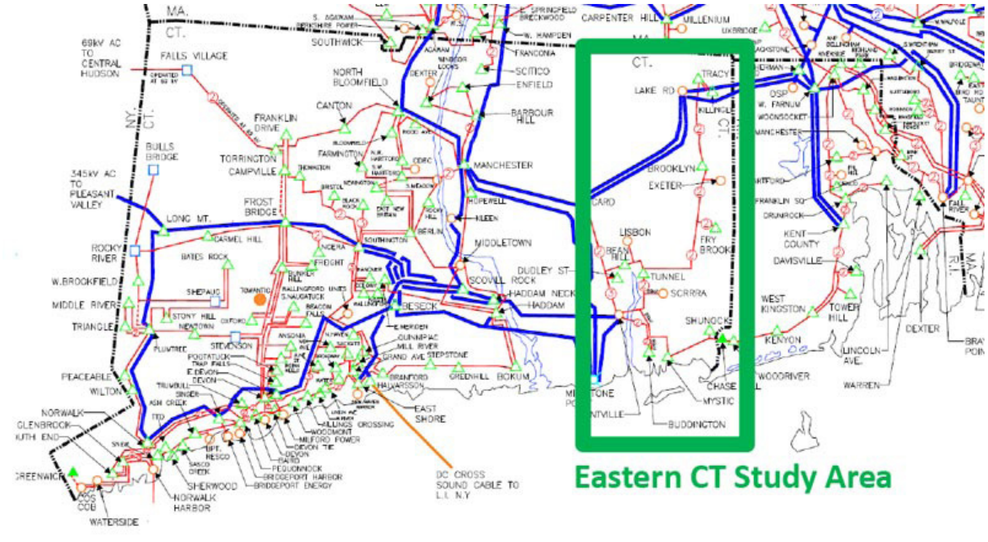
Kumar, a senior transmission planning engineer, said the solution was chosen from four 115-kV and 345-kV alternatives in the RTO's final review. All the finalists also require the installation of a 115-kV breaker in series with breaker 4 at Exelon's Mystic generating plant to eliminate a breaker failure contingency, a project estimated at $3.25 million.

Together, the two solutions are estimated at $8.72 million (+50%/-25%).

Kumar said the cost estimate and expected in-service date were the most important factors in the RTO's selection.

The winning project was the cheapest among the options that could be in service in 2021.

Because it is time-sensitive, it will be installed by National Grid. A need is considered time-sensitive — and excluded from competitive bidding — if the improvements are required within three years of a completed needs assessment.



Eastern Connecticut study area | *ISO-NE*

Needs Update Reduces Thermal Violations

The RTO also briefed the PAC on its updated study of non-time-sensitive needs in the Boston study area, which will be the subject of a request for proposals in the fourth quarter. The update incorporates the Golden Hills reactor and system changes since the finalization of the Boston 2028 Needs Assessment in June.

The update made several changes to resource assumptions:

- The New England Clean Energy Connect (NECEC) and Revolution Wind offshore wind projects were added to the model after providing approved contracts to the RTO. NECEC, a transmission line that would deliver Canadian hydropower to New England, was modeled as a 1,090-MW injection at the Larrabee Road 345-kV substation in Maine. Revolution Wind was modeled as a 120-MW injection at the Davisville 115-kV line in Rhode Island. Both were modeled at 20% of their nameplate capacity.
- Resources that filed retirement and permanent delist bids for Forward Capacity Auction 14 were removed from dispatch assumptions.
- The model uses FCA 13 active demand capacity resources (ADCRs), updated from FCA 12.
- Resources outside Boston that filed retirement and permanent delist bids for FCA 13 have been removed from dispatch.
- An "asset condition" project to refurbish the 110-510/511 cables in downtown Boston was added.

The needs assessment posted on June 10 identified one N-1 and six N-1-1 thermal violations under peak loads, all considered non-time-sensitive needs. The updated analysis eliminated three N-1-1 thermal violations: on the Woburn-Wakefield Junction 345-kV and Stoughton-to-K Street 345-kV circuits 1 and 2.

Four other thermal violations identified in the June 2019 Needs Assessment remain:

- N-1 Thermal Overload: W. Amesbury–King St. 115-kV line;
- N-1-1 Thermal Overload: circuits 1 and 2 of the Woburn-North Cambridge 345-kV lines; and
- N-1-1 Thermal Overload: North Cambridge–Mystic 345-kV cable.

Mystic Reactor


Mystic Generating Station

ISO-NE's Pradip Vijayan updated the PAC on revisions to the *requirements* for a 300-MVAR dynamic reactive device needed for system operations after the retirement of Mystic Units 8 and 9. Exelon announced last year that it would retire Mystic in 2022, but FERC approved a cost-of-service agreement between the company and ISO-NE to keep Units 8 and 9 operating through May 2024.

Since the Aug. 8 PAC meeting, RTO staff reduced the device's requirement to provide full leading capability at 1.05 per unit voltage at the point of interconnection (POI), down from

ISO-NE News

the original 1.1. The requirement to provide full lagging capability at 0.9 per unit voltage is unchanged.

Staff also amended some of the reactive power requirements for clarity, saying the device must provide continuous voltage control at the POI and must not stay in standby mode (providing no reactive power) under normal operating conditions.

The reactor is considered non-time-sensitive.

The RTO plans to finalize the Boston 2028 Solutions Study next month. Stakeholder feedback on the selection and the study report, which was *posted* Sept. 24, are due on Oct. 9. Comments should be sent to *pacmatters@iso-ne.com*.

"You can look for an RFP [on the non-time-sensitive needs] in December," said the RTO's Eva Mailhot. "That's our Christmas present to you guys," she joked.

Eastern Connecticut 2029 Needs Assessment

ISO-NE's Jon Breard provided an update on the Eastern Connecticut (ECT) 2029 Needs Assessment, which was suspended in February because changes in the 2019 draft capacity, energy, loads and transmission (CELT) forecast indicated the net load figures in the ECT 2027 assessment were too high. The 2019 CELT shows changes in load, energy efficiency and solar PV from the 2017 CELT.

The revised ECT needs assessment considers future load forecasts, resource changes based on FCA 13 results, coordination with proposed Southeastern Massachusetts and Rhode Island (SEMA/RI) projects, and NERC, ISO-NE and Northeast Power Coordinating Council (NPCC) reliability standards.

Category	Summer Peak 2029 90/10 Load (MW)	Summer Peak 2022 90/10 Load (MW)
CELT Forecast	32,468	30,805
Fixed New England load	N/A	N/A
Non-CELT Manufacturing load in New England	318	318
Available FCA-12 ACDR (modeled as negative load)	-478	-478
Available draft 2019 CELT EE Forecast for study year (modeled as negative load)	-5,284	-4,144
Available draft 2019 CELT PV Forecast for study year (modeled as negative load)	-1,825	-1,202
Net load modeled in New England (Excludes Station Service)	25,199	25,299

Projected New England load levels, 2022 vs. 2029 | *ISO-NE*

Also included were NECEC and the Vineyard Wind and Revolution offshore wind farms.

The CELT 2029 90/10 summer peak load forecast is 32,468 MW, an increase of 1,663 MW over the 2022 forecast. However, net load excluding station service decreased by 100 MW because of increased forecasts for energy efficiency and PV production.

The report concludes that non-transmission options were not able to correct the reliability violations in ECT.

All needs are time sensitive and located on the systems of Eversource Energy, National Grid and Connecticut Municipal Electric Energy Cooperative, the RTO said.

The RTO plans to post the draft ECT needs assessment next month, with the final report expected to be posted in the fourth quarter.

The study found no N-0 violations in ECT or neighboring areas and one N-1 low-voltage violation and no N-1 thermal violations in the ECT area. Steady-state peak load results identified seven N-1-1 violations.

The RTO plans to post the final needs assessment report in the fourth quarter.

Transmission Planning Technical Guide Short-circuit Requirements

The RTO's Faheem Ibrahim briefed the committee on *proposed assumptions* for conducting short-circuit analyses using an ASPEN OneLiner.

Such analyses are used in generator interconnection studies, system impact studies, needs assessments, solution studies, and NERC and NPCC compliance studies.

Ibrahim said having a single set of study conditions and solution parameters in the Transmission Planning Technical Guide will ensure consistency across the different studies.

Comments on the revised guide are due to *pacmatters@iso-ne.com* by Tuesday. ■

Solution Alternative	Solution Component	Cost Estimate ($M) (+50%/ -25%)	In-service Date
1	160 MVAR reactor at Golden Hills 345 kV	5.47	September 2021
2	76 MVAR reactor at Lexington 115 kV	6.70	June 2021
3	76 MVAR reactor at K Street 115 kV	9.10	June 2021
4	76 MVAR reactor at Everett 115 kV	5.70	June 2022
Common	Install a 115 kV breaker in series with breaker 4 at Mystic to eliminate the breaker failure contingency	3.25	June 2021

ISO-NE selected a 160-MVAR reactor at the Golden Hills 345-kV substation as the cheapest solution to correct high-voltage violations expected at minimum load levels in the Boston area in 2028. | *ISO-NE*

ISO-NE News

Overheard at NECA 2019 Fuels Conference

Focus on Natural Gas Highlights 'Virtual' Pipelines

MARLBOROUGH, Mass. — Natural gas — and even renewable gas — will be crucial to the national economy and the New England electric power system for years, industry experts told participants at the Northeast Energy and Commerce Association (NECA) 2019 Fuels Conference on Thursday.

If the gas cannot arrive by pipeline, it will arrive by "virtual" pipelines, such as trucks, barges or tanker ships, participants heard.

Cheryl LaFleur, ISO-NE | © *RTO Insider*

In her first speech since leaving FERC a month ago and moving back to the Boston area, former Commissioner Cheryl LaFleur shared her perspective on changes she's seen in the natural gas world in the past decade. Earlier in September, Lafleur was elected to a three-year term on ISO-NE's Board of Directors. (See ***LaFleur Elected to ISO-NE Board***.)

"Most of our work at FERC over my terms was driven by three big changes. The first is the growth of natural gas; the second is the growth of renewables, storage and demand-side technologies; and the third is the growing understanding of and concern about the climate impacts of energy," LaFleur said.

Climate is the most prominent of those three issues today, she said.

"But over the sweep of the past decade, I would make a pretty strong argument that the changes in the growth and availability and the affordability of domestic natural gas were the biggest change driver," LaFleur said.

Gas supply constraints were an issue when Lafleur joined FERC in 2010, and the commission received petitions to build half a dozen LNG import terminals. But as the shale revolution took off and gas production kept increasing, industry players began to think about exporting instead of importing, she said.

People at the time saw natural gas as an environmental hero, cutting emissions as it displaced dirty coal and fuel oil, but the perception shifted when gas became so cheap that it started threatening the margins of nuclear plants and even baseload hydropower, which had been thought of as unassailable, LaFleur said. Suddenly gas was the villain.

Former FERC Commissioner Cheryl LaFleur speaks at the NECA 2019 Fuels Conference on Sept. 26. | © *RTO Insider*

"With the growth of pipeline construction, particularly in highly populous regions that were not traditionally producing regions, came an increased focus on the environmental costs of the pipelines, especially the methane leaks," LaFleur said.

She urged people who operate pipelines to "follow the safety rules," for an incident of carelessness by one firm taints the reputation of every firm.

Toward a Greener Future

On the Trump administration reversing environmental policies and procedures from the Obama era and earlier, LaFleur said, "My belief is that the long-term trend is still toward a greener electric system and more concern about climate, but it's obvious to anyone who owns a TV that there's no national consensus on the climate, that it's a challenge, or that we need a solution."

"It's been a wedge issue that really changed the operation of what has been a bipartisan commission that did most of its work unanimously.

"In Washington, the same people talk to each other in the same echo chamber," LaFleur said. "The climate-focused people go to their meetings and other people go to their meetings."

It's important to listen to people with opposing views and try to understand them, she said.

In response to a question on the states' rights battle between California and the Trump administration on car emissions, LaFleur said. "If you look at the environmental rules, I believe they were written to set a baseline and allow states to do more. A state could have stronger rules, but it has to meet this environmental baseline.

"You're not going to put the genie back in the bottle once states that have set their targets," she said. "Conceptually I am more of a federalist, but you have to look at the situation honestly."

Jack Weixel, IHS Markit | © *RTO Insider*

Although the natural gas industry is at its most robust period ever historically, it's still subject to much uncertainty, said Jack Weixel, senior director at IHS Markit.

"The ability to build pipelines in various parts of the country is increasingly more difficult," Weixel said. "Domestic demand growth, as is evident very clearly here in New England, is limited. Basically, that is pushing incremental growth to the export market. LNG exports have come on in a big way and are going to continue to do so for the foreseeable future."

However, "if you were to stop drilling new wells in the U.S., you'd see production fall off by 28 Bcfd," Weixel said, cautioning that a federal mandate to stop such drilling would "take a third of the industry away."

Supply Constraints

Michael Sloan, ICF | t© *RTO Insider*

Michael Sloan, managing director of the natural gas and liquids advisory services group at ICF, said he has been talking with a number of utilities, including Consolidated Edison, about what pressures they're facing and the potential for non-pipe solutions to address capacity issues.

"A lot of utilities in the Northeast and in other areas have very significant capacity investment programs," Sloan said. "Those investments will add significantly to the rate base, and there is a concern about the long-term recovery of those costs, the long-term usefulness of those assets from some of the stakeholders in the process,

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and the regulators."

Utilities in different parts of the country are banning new gas connections, and they ask if non-traditional means will enable them to meet customers' peak energy needs in a cost-effective, reliable and timely fashion, he said. "If the answer is 'no' to any of the parts of that question, it is not an effective non-pipeline solution."


Jordan Stone, Peregrine Group | © *RTO Insider*

Jordan Stone, principal at Rhode Island-based real estate developer *Peregrine Group*, said he and his partner panicked last January upon hearing that National Grid might not be able to deliver the gas they had promised to their $29 million Hammetts Wharf hotel project in Newport, for which they had just broken ground.

"As part of the due diligence for a developer, before you close on your debt you go to each utility ... and ask for 'letters to serve,'" Stone said. "We had those. We quickly learned that those letters don't mean a whole hell of a lot."

Their initial heating and cooling choices for the hotel were between gas-fired heat pumps, an all-electric, variable refrigerant flow system, or propane, whose tanks could not be placed so close to the water, he said.

National Grid eventually gave assurances to supply the gas, probably with "a non-pipeline solution so this would not happen again," Stone said. "We're going into this with our fingers crossed that they can actually deliver gas in January or February, when it's cold, and they won't have another shutdown like they did earlier in 2019 when they shut off supply to 7,100 homes and business due to lack of supply."


Michael Holt, NG Advantage | © *RTO Insider*

Michael Holt, senior director of business development at NG Advantage, a Vermont-based shipper of LNG, said that "as we see gas moratoriums in New England, we want to recognize what is causing them."

"One cause is a lack of gas supply in New England ... and the other part of the problem could be that some of these moratoriums are actually being encouraged by local folks who are more satisfied with the status quo and are not interested in seeing infrastructure development for fossil fuels or economic growth."

There is growing demand in the northeast, and New York City has been going through a major transition over the past decade away from heating oil and to natural gas, so demand is rising rapidly, he said.

"In New England it matters more about the critical hour or day, because most of the time the gas supply is fine," Holt said.


David Kailbourne, NiCHe LNG | © *RTO Insider*

David Kailbourne, COO of *NiCHe LNG*, a Pennsylvania-based joint venture between Dominion Energy and REV LNG, said that trucking gas is fast, efficient, affordable and safe.

"We are able to get the gas to customers when and where they need it within a day, rather than the yearslong process of permitting and building a pipeline," Kailbourne said.

He said his firm handles a range of projects, from bridging a pipeline outage down south and directly serving a chemical plant to supplying a utility in Texas with an LNG solution for a small town reliant on wells with declining yields.

A Changing World


Tamara Nameroff, Shell New Energies | © *RTO Insider*

Tamara Nameroff, general manager for policy and advocacy at Shell New Energies, said Shell trades more than 7 Bcf of natural gas a day, controls more than 9,500 MW of generation capacity, and sells more than 270 million MWh of power each year.

The deep pockets of a global company like Shell are one reason why it's important for them to invest in renewable energy, because it has the balance sheet to "move the needle" on renewables, Nameroff said.

Regarding ambitious state goals to achieve net-zero emissions, Nameroff said, "Parts of the world are changing quite quickly. We found that the policy around that is moving much faster than it might have even a decade ago, so that's helping us respond more quickly. We need some time to move the ship, but it's always good to keep the tension on us to get us to move. If you don't set the bar high enough, you don't compete."

One nascent area of development is renewable natural gas (RNG), which is pipeline quality gas made from biomass or other renewable sources that have lower lifecycle CO2 emissions than geologic natural gas.


Brian Jones, M.J. Bradley Associates | © *RTO Insider*

Brian Jones, senior vice president at M.J. Bradley and Associates, said, "Only when the grid is around 85% zero-emitting will it equal the value of RNG, so [that's] a pretty compelling emissions signature for RNG."


Lizzy Reinholt, Summit Utilities | © *RTO Insider*

Lizzy Reinholt — senior director of sustainability and corporate affairs at Summit Utilities, a small natural gas company that operates in Maine, Missouri, Arkansas, Oklahoma and Colorado — described the company's RNG work in Maine, where she said about 60% of the state's homes are heated with heating oil: "just huge emissions."

Summit in 2012 began "building out natural gas infrastructure in areas where other utilities just wouldn't go, like the suburbs of Portland and the Kennebec Valley area, where we have a number of industrial customers that were using a lot of oil to power their facilities," Reinholt said.

"Since coming to Maine, we estimate that we've reduced carbon emissions by about 69,000 metric tons a year, which is like taking 15,000 cars off the road," she said.

About 12% of the natural gas used in Quebec could be replaced with RNG with the technology available today, said Julien Sauvé, RNG and renewable energy adviser at Énergir, the largest natural gas distribution company in Quebec.

"By 2030, with the inclusion of the second technology of gasification of organics, it's more than two-thirds of all the gas we distribute that could come from renewable sources," Sauvé said. ■

— Michael Kuser

Overheard at the 163rd NE Electricity Restructuring Roundtable

New Regulatory Chiefs Share Policy Plans; OSW Developers Look to Future

BOSTON — New chief utility regulators from Connecticut, Massachusetts and Maine last week shared their visions of grid modernization and resource adequacy at Raab Associates' 163rd New England Electricity Restructuring Roundtable.

The regulators were followed by a panel of all three offshore wind developers that bid into the latest solicitation out of Boston, who discussed the region's huge baseline generation goals with an industry expert, an independent transmission developer and a state procurement official.

The following is some of what we heard during the morning.

Grid Modernization

Marissa Gillett, Connecticut PURA | © *RTO Insider*

Marissa Gillett, chair of the Connecticut Public Utilities Regulatory Authority, said her agency expects to release a grid modernization order imminently, possibly within the next week, and that it is also busy exploring how to help roll out 5G in the telecoms sector and dealing with lost and unaccounted for gas in the natural gas sector.

"I am new to the culture in Connecticut, and what I mean by that is every state has their own setup about what they view as the role of the regulatory commission, versus what they view as the role of the energy office, versus the governor and the legislature," Gillett said. She came to PURA five months ago from the Energy Storage Association, and previously worked as an adviser to the Maryland Public Service Commission.

"I'm looking forward to pushing the envelope [at PURA] and launching a grid modernization proceeding that will take probably upwards of two years to get through," she said. "We're looking to get new leads on a number of topics."

Those topics include energy storage, electric vehicles, advanced metering infrastructure and innovative rate designs.

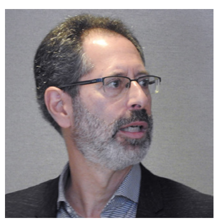
Her predecessor, Katie Dykes, currently commissioner of the state's Department of Energy and Environmental Protection, "now has the authority to procure up to 98% of the resource needs in Connecticut," Gillett said. "It has not all been utilized at this point, but she has that authority."

The challenge is figuring out how all those procurements "piece together in the building blocks of, dare I say it, resource adequacy ... and figuring out how that weaves its way into the grid modernization conversation," she said.

Affordable, not Cheap

"When people hear 'grid modernization,' they think 'cost,' but energy affordability does not mean cheap electricity, it means affordable," Gillett said.

"Folks look at electricity rates as being limited to the poles and wires, what it takes to deliver that commodity," she said. "But since coming here, I've learned that certain states approach electricity and electrification of their economy as an economic development opportunity."



Jonathan Raab, Raab Associates | © *RTO Insider*

Raab Associates' Jonathan Raab, who conducted the roundtable, asked how residential rate design must evolve to achieve two things at once that may conflict with each other.

"One is to try and get EV charging off the peak when possible, and the other is not to scare away people using heat pumps, where the heating and air conditioning use is often more coincident with the peak," Raab said. "How do we design a rate that can do both things, or do we have different time-of-use rates for either?"

"I have a couple of competing views about time-of-use rates," Gillett said. "Rate design is going to be a critical component of the grid modernization process ... so there are opportunities for innovative rate design that include TOU rates, even for the residential sector."

The second half of the equation is asking whether TOU rates are the way to go, she said.

"One of the most obvious ways for Connecticut to decrease its electricity prices would be to increase its electricity sales," Gillett said. "So if my primary goal is to electrify the economy, thereby increasing electricity sales, how does that pair with the concept of time-of-use rates. ... If you're going to shift the peak, then you have to shift the time-of-use rates ... but there other ways to shift the peak.

The 163rd New England Electricity Restructuring Roundtable took place in Boston on Sept. 27. | © *RTO Insider*

"Figure out what the most pressing objective is and pair that to the long-term goal," she said.

Phil Bartlett, Maine PUC | © *RTO Insider*

Maine Public Utilities Commission Chairman Phil Bartlett said it would be helpful "to imagine multiple styles of TOU rates. ... If somebody is doing all new appliances, that's one model; if they're just getting an EV, that's another. ... There has to be some real nuance to the design."

Bullish on EVs, Electrification

Matthew Nelson, Massachusetts DPU | © *RTO Insider*

Matthew Nelson, chairman of the Massachusetts Department of Public Utilities, arrived at the last minute because he was overseeing the response to a major pre-dawn gas leak that caused the evacuation of 100 residents in Lawrence, one year after the city suffered catastrophic gas line explosions.

"The area is safe, but there's lots of work left to do," Nelson said.

Of distributed generation, Nelson said, "Massachusetts has one of the largest scales of [distributed generation] on the distribution system ... and that is starting to tax the distribution system and starting to tax developers and slow down the process of getting people interconnected."

The high-volume queues are an issue, he said:

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"How do we give clarity to developers?"

Beyond distributed generation, Nelson said he is "very bullish on electric vehicles ... which are objectively better than gas cars: lower costs to maintain, lower fuels costs and gas stations are terrible ... but is the system ready for fleet charging?"

"Electrification is the right policy, but I'm worried about implementation," Nelson said. "How are we going to get away from oil and gas when they're central to our peak load generation?"

Building Offshore Wind

Stephanie McClellan, director of the Special Initiative on Offshore Wind (*SIOW*) at the University of Delaware, *showed* that states up and down the East Coast have approved or committed to procure more than 22 GW of offshore wind energy.

Stephanie McClellan, SIOW | *© RTO Insider*

"Commitments and aspirations are one thing, but states actually acting swiftly and efficiently on those commitments is really where the rubber meets the road in this industry," McClellan said. "The big takeaway from this is that half of that big pipeline of committed projects is already in process."

While the U.S. Bureau of Ocean Energy Management expands analysis of cumulative environmental impacts of Vineyard Wind, McClellan said, "in these early days of establishing a supply chain, those areas, regions and developers who can solve the industry's problems and move through this regulatory hiccup will benefit that region."

"I do think this is going to shape up as a regional competition, and not a state competition," McClellan said. "How are Massachusetts, Connecticut and Rhode Island going to compete in a regional way? Regional marketing is something that states can do together... but ultimately, offshore wind will succeed as a U.S. industry, not as a regional one."

Patrick Woodcock, Mass EEA | *© RTO Insider*

Massachusetts Undersecretary of Energy Patrick Woodcock *said* the fundamentals of offshore wind energy address "what I see as our biggest challenge as a region, of reliability and energy security in the winter. It is really at the point where I am most confident in the near term of justifying this for Massachusetts ratepayers."

Regarding BOEM's expanded analysis, Woodcock said, "I do want to highlight for this region not to look through this with a prism just for this project [Vineyard Wind] ... but we should establish that permitting any project of this size is going to have environmental impacts."

What Developers Say

Erich Stephens, chief development officer for Vineyard Wind, said his company is pursuing many projects but is on pause right now, with the 800-MW project close to completing state and local permits while BOEM expands the scope of analysis.

Erich Stephens, Vineyard Wind | *© RTO Insider*

Stephens called for more land-based grid connection development, saying "the offshore part is relatively easy, constrained mostly by technical considerations, by how much power you can put down on a single cable. The hard part is where do you bring that cable."

He *showed* four interconnection points in Massachusetts that "each can take 1,000 MW on a good day."

"While we're going to be able to get through these first rounds, we're already at the point of needing to look at what are we going to do onshore to bring all this power off," Stephens said. "The grid is indifferent to whether that interconnection is coming from an independent developer or from a generation developer, and the problem really is with the onshore part of it.

"I hate to say it, but it's looking a lot like what is going on up in Maine ... where you have a lot of generation trying to get into a pretty small area in the electric grid," he said.

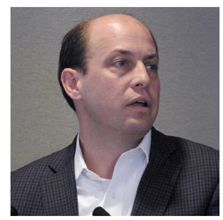
Ed Krapels, CEO of Anbaric, agreed in part, saying that up to 50 GW of new power sources "means you're talking about a transmission system ... and the big picture is what do you do to handle all that power?"

Ed Krapels, Anbaric | *© RTO Insider*

A well-planned ocean grid minimizes the need for onshore transmission upgrades, he explained.

"You need a plan, and it was in that spirit that ... in New York and New England we filed a non-exclusive right-of-way application with BOEM, which got BOEM thinking about what the cumulative impacts of all these new transmission connections to shore would be," Krapels said during a *presentation*.

Grid planning is critical to lowering the long-term costs of offshore wind, and a transmission company will perform a useful role if it tells policymakers what they need to know, Krapels said.



David Hang, Ørsted | *© RTO Insider*

David Hang, president and head of development at Ørsted, *said* the company's offshore wind development portfolio in the U.S. totals about 3 GW and that he's most proud of the 130-MW South Fork project being built for the Long Island Power Authority.

"What I love about that project [is that] it was not a renewables solicitation; it was an all-source solicitation, and we beat storage, we beat peaker plants, and LIPA had a problem at a specific substation they needed a solution for, and offshore wind came and filled that void," Hang said.

"We need to look at things on a long-term basis, not necessarily on a project-by-project view," Hang said.

"As I've said before, how can we still screw this up?" he said, stressing the need for interactive stakeholder outreach and the importance of the first couple of projects delivering on the promises the developers have made to various partners and stakeholders. "There's a lot of momentum here, but it's still nascent; there are still only 30 MW that have ever been built [in the U.S.]."

John Hartnett, president of Mayflower Wind Energy, a joint venture between Shell and EDP Renewables, said, "The commercial business is going to drive the industry much more than the state solicitations." ■

John Hartnett, Mayflower Wind | *© RTO Insider*

— Michael Kuser

MISO News

Despite Pushback, MISO Pursuing TO-only SATA

By Amanda Durish Cook

CARMEL, Ind. — MISO plans to file its first storage-as-transmission asset (SATA) ruleset this month, despite complaints from some members that the proposed provisions limit resource ownership to transmission owners.

Speaking at a Planning Advisory Committee meeting Wednesday, DTE Energy's Nick Griffin said he and others still see an "equality" issue with the ownership restriction. Griffin has told MISO's Board of Directors that if the provision remains in the filing, DTE would file a protest in the docket arguing that similarly situated parties stand to be treated inequitably. (See *MISO Limits Storage as Transmission Asset Ownership* and *MISO Firming Up 1st SATA Ruleset*.)

Discussion at the PAC meeting quickly waded into murky waters over what it means to be a TO and what constitutes a transmission asset.

Griffin has suggested a compromise in which MISO allows non-TOs to own storage that provides reliability transmission services while simultaneously completing the approximately three-year interconnection queue to allow the asset to become a market-based generator. The resource would initially be classified as a transmission asset, then transition to a market resource.

"We can't defer transmission unless we have an assurance that the transmission alternative" will be there, MISO Director of Planning Jeff Webb said. "If it's built and constructed and goes into service — and it can't participate in the market until it goes through the queue — what if it never goes through the queue? Who pays for that? Where are you going to get your cost recovery?

Jeff Webb, MISO | © *RTO Insider*

"That's the fundamental problem we're having: What is a transmission asset? This feels like a transmission asset owned by a non-transmission owner," he said. "I'm really worried about the slippery slope here; it's a gateway drug. The next question might be, 'Hey, can I do this with a peaking gas generator?' … We have to find a place for [SATA] that respects our framework."

"I think already in this process there's a lot of gray area between transmission and non-transmission assets [NTAs], and unfortunately, that's where FERC has left us," Clean Grid Alliance's Natalie McIntire said. Part of the gray area stems from MISO not having a particularly clear definition of NTAs, she said.

"The dream I have is we would abolish the term 'non-transmission alternatives' and define it for what it is versus what it's not," Webb said.

MISO has one SATA project proposed for Wisconsin in this year's Transmission Expansion Plan (MTEP), making the filing a bit of a race against the clock because the RTO doesn't yet have cost recovery in place. (See *MTEP 19 Could Yield First MISO SATA Project*.)

Webb said it's unlikely that FERC will rule on the SATA rules by the board's approval of MTEP 19 in December. Because MISO doesn't want to proceed with an uncertain project, it will likely formally recommend the storage project after the usual December timeline. PAC Chair Cynthia Crane said RTO planning staff can appear before the board at the March 2020 meeting to make a one-off recommendation for a project.

MISO began drafting SATA provisions in August to be included in its business practices manual covering transmission planning processes. The drafts place several mentions of electric storage resources into *BPM 20*, the existing rules on selecting NTAs in place of transmission projects. The provisions would add an inverter-based reliability analysis and allow the RTO to consider the life cycle, degradation and cost assumptions of storage resources, as well as the impacts on proposed generation in the interconnection queue. The changes would also require SATA operators to develop an operating guide for each asset approved in the MTEP process.

But MISO will now put the proposed BPM edits on hold, pending the outcome of the FERC filing, responding to the complaints of stakeholders who said they were premature. Several members said MISO shouldn't create BPM provisions before defining a method for evaluating SATA projects.

"The BPM was a vehicle to vet changes," Webb said, explaining the BPM is subject to revision to align with whatever version of Tariff revisions FERC accepts. He said the minimal BPM edits are simply the "essential features" to implement SATA. ■

MISO News

More MISO Members Join Call for Tx Planning Change

By Amanda Durish Cook

CARMEL, Ind. — A growing number of stakeholders are prodding MISO to create a task team to improve transmission planning assumptions and devise ways to prevent new generation projects from becoming responsible for most transmission development.

Multiple stakeholders at a Planning Advisory Committee meeting Wednesday said MISO's lagging renewable forecasts and increasingly pricey network upgrades for queue projects merit examination by a new task team.

Natalie McIntire, Clean Grid Alliance | © *RTO Insider*

Clean Grid Alliance's Natalie McIntire *said* MISO's 15-year *futures* — even the accelerated fleet change scenario — project smaller renewable growth than indicated by projects that have already signed interconnection agreements in the queue. Projects set to come online in the next few years eclipse all futures expectations, she said.

Representatives from the Organization of MISO States and CGA appeared before the RTO's Board of Directors in mid-September to warn about the increasing trend of otherwise economically viable renewable projects exiting the queue because of prohibitively expensive network upgrades. (See *MISO Readies MTEP 19, Debates Futures Change*.)

MISO has promised to evaluate special, targeted economic planning studies in its 2020 Transmission Expansion Plan (MTEP 20), while postponing a futures overhaul until the 2021 cycle. (See *MISO Halts Futures Work for 2020, Plans 2021 Rebuild*.) During the PAC meeting, MISO project manager Sandy Boegeman asked stakeholders for suggestions on the targeted studies.

Several members have said the RTO cannot afford to wait another year before recasting its future scenarios. MISO will essentially snub transmission projects designed to help facilitate the renewables growth indicated by the interconnection queue, creating a self-fulfilling prophecy, they say.

The accelerated fleet change future should now be considered MISO's base case future scenario, while the three other futures are "not at all representative of what we might expect," McIntire said Wednesday. She called for a "better alignment" between planning assumptions and queued generation projects.

McIntire said the Helena-to-Hampton Corners second circuit project should be included in MTEP 19 as a market efficiency project, a contention her organization already put before the board. (See *MISO Readies MTEP 19, Debates Futures Change*.) The $36.1 million, 345-kV project, originally identified in this year's Market Congestion Planning Study, was set to solve congestion in southern Minnesota at a 4.22:1 benefit-to-cost ratio, but MISO said the project quickly lost value once forecasted wind generation was removed from the equation.

McIntire said there was "not a very robust stakeholder process" around testing of the project, which should have been subject to more vetting and a PAC review.

She also said network upgrades borne by new generators in the queue "provide benefits well beyond simply interconnecting generators." She pointed out that the February 2017 definitive planning phase studies showed that the batch of projects needed more than $1.3 billion in upgrades, an average of $1.5 million per megawatt of new generation.

"It is not efficient or cost-effective for MISO to plan the system one interconnection queue at a time," said McIntire, who issued the first call for a task team to examine network upgrades and transmission planning. She said MISO should also consider creating a new transmission project category that allows for cost sharing between generators and load.

At a special *workshop* on MTEP futures Thursday, MISO Planning Manager Tony Hunziker said the RTO is developing a strawman proposal on new futures development for stakeholder review at an Oct. 17 workshop.

Hunziker agreed that industry projections are already "outpacing" even MISO's accelerated fleet change future, which predicts wind and solar will account for 29% of capacity by 2033. He said there are signs that wind and solar generation will make up more than 30% of the generation mix by that time.

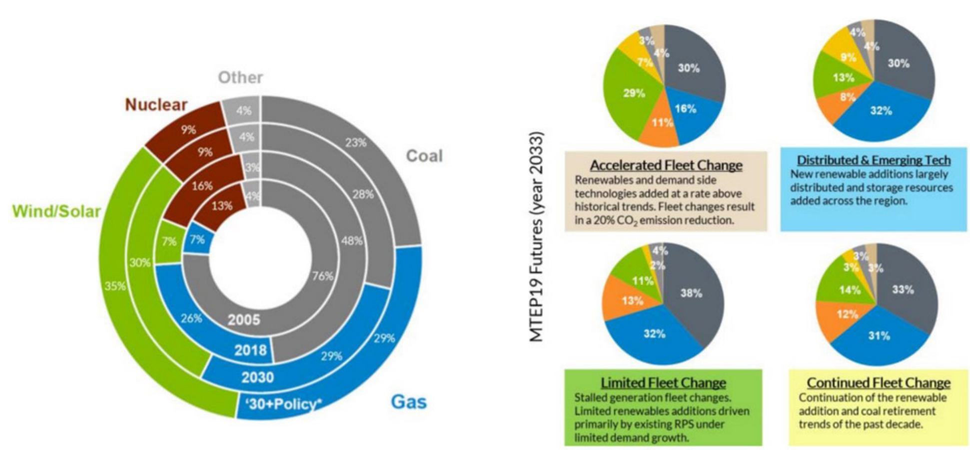
CGA's Sean Brady noted that some MISO states are targeting a 40 to 50% renewables mix by the mid-2030s.

Veriquest Group's David Harlan said MISO's reliance on planning for new generation based on a reliability-focused planning reserve margin might now be "too narrow" to use in transmission planning. He said MISO should consider that the future generation portfolio will have ramping, reactive power and voltage support needs among others.

Hunziker said MISO could move to a "dynamic" — instead of static — planning reserve margin for transmission planning. Though still undefined by the RTO, a dynamic planning reserve margin could change in out-years based on forecasts. Currently, MISO's futures ensure its planning reserve margin is met.

Some stakeholders have also suggested MISO create a member survey to better capture its members' carbon-reduction goals and resource additions and retirements.

MISO is also asking whether it should split its footprint into subsections for planning studies or allow for different input assumptions at the local resource zone level, state level, or the MISO Midwest and South regions. Hunziker said subregional futures would require significantly more work. ■



MISO historical fuel mix and current futures | *MISO*

MISO News

OMS: 4.5 GW of Unregistered DERs in MISO

By Amanda Durish Cook

CARMEL, Ind. — MISO is home to more than 4.5 GW of unregistered distributed energy resources, much of it for nonresidential use, the Organization of MISO States estimates.

The figure comes from OMS' annual DER survey, which was presented to MISO stakeholders at a special workshop last week.

The total breaks down to 1.2 GW of residential and 3.4 GW of nonresidential capacity, much of which is solar. Unsurprisingly, the group found that residential installations tend to be smaller than nonresidential, said Tricia DeBleeckere, senior planning director for the Minnesota Public Utilities Commission.

DeBleeckere said utility interconnection requests remain the primary source of data on DERs.

This year's numbers are up sharply over last year's, which showed 2.5 GW of unregistered DER capacity. OMS said unregistered residential capacity increased by 170% year over year, while nonresidential rose 62%. By comparison, MISO contains about 12 GW of registered load-modifying resources.

OMS also noted that the RTO is home to about 31 DER pilot programs.

Of the roughly 50 utilities that responded to this year's survey, more than half said they were considering investments that could improve their DER visibility. Eleven said they were considering implementing some type of DER management system.

Still, most survey respondents said they have yet to experience a transmission-level impact stemming from DER use. The utilities also said low natural gas prices appear to be discouraging some types of DER adoption and encouraging others, such as customer-owned combined heat and power.

In August, FERC asked RTOs for detailed information on aggregated DER portfolios in their wholesale markets — the first significant movement in a possible rulemaking on DER in more than a year. (See *FERC Sends DER Data Request to RTOs*.)

MISO counsel Michael Kessler said the RTO is also still evaluating FERC's data request before it decides whether to reach out to members for help with DER estimates.

"We're still figuring out where we're going on the responses," Kessler said.

Meanwhile, MISO is still waiting on FERC to provide a clear definition of DER before the RTO begins work with stakeholders on a possible participation model.

"We're waiting for FERC to define what it is," DER Program Manager Kristin Swenson told stakeholders.

Swenson predicted that several players will need to be involved to plan for and manage an influx of distributed resources. She also said there is much speculation within MISO over what a possible Notice of Proposed Rulemaking might look like.

"We have to work very closely with regulators on the state level," Swenson said. "MISO has a piece of this. Transmission has a piece of this. Consumers have a piece of this. … It's going to take some time, and that's why we're here today."

There are a "million ideas" but "no golden rule yet," MISO adviser Robert Merring said.

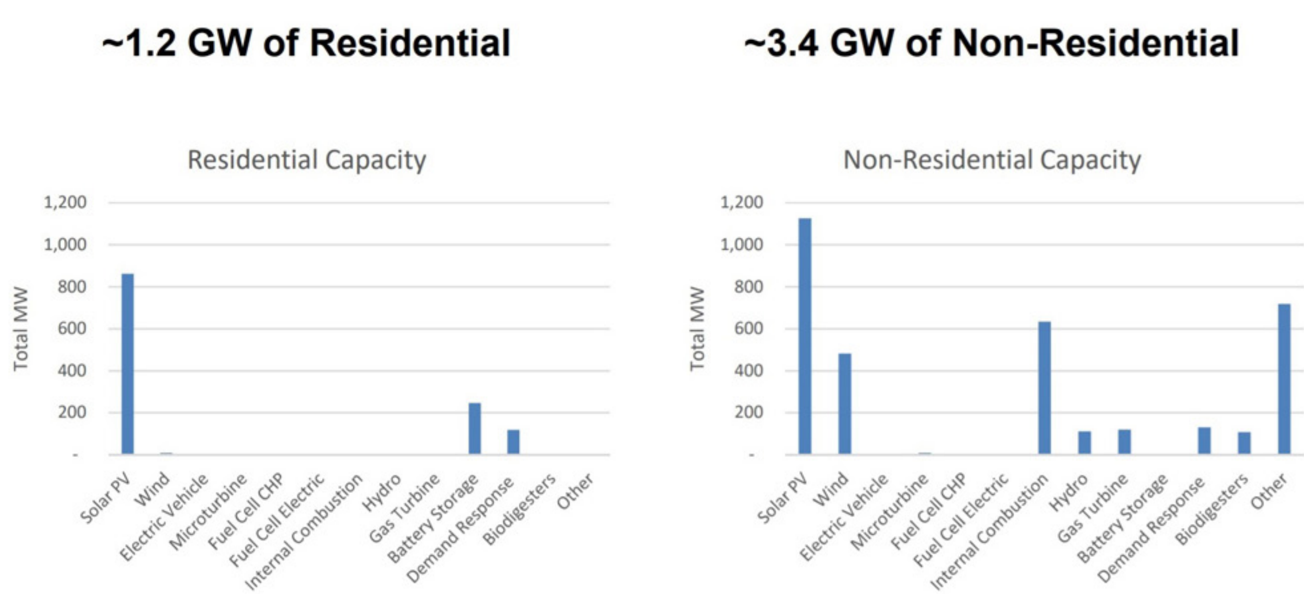
MISO also admits it needs to improve existing market paradigms for more distributed participation, including the registration process, communication system and demand response resource tool, which is used to collect meter data for the settlement of LMRs after they're called up for emergency events.

"We recognize we have a disparate set of tools to manage these resources, and we're working on that," MISO adviser Michael Robinson said.

WPPI Energy economist Valy Goepfrich said the future level of interest in DERs remains an open-ended question. She said integration into the wholesale markets would likely depend on economics but noted that her company's LMRs currently have little interest in forging ahead into wholesale markets themselves.

"The wholesale market is a tough business. It's not for the faint of heart. That's why we're all regulated utilities," she said, smiling.

MISO will resume DER workshops in November and through early 2020. ■



Estimated unregistered DER in MISO | *OMS*

MISO News

MISO Zeroes in on Queue Overhaul Filing

By Amanda Durish Cook

CARMEL, Ind. — MISO will soon take a second crack at getting FERC approval for Tariff revisions intended to thin out and speed up its overflowing generator interconnection queue.

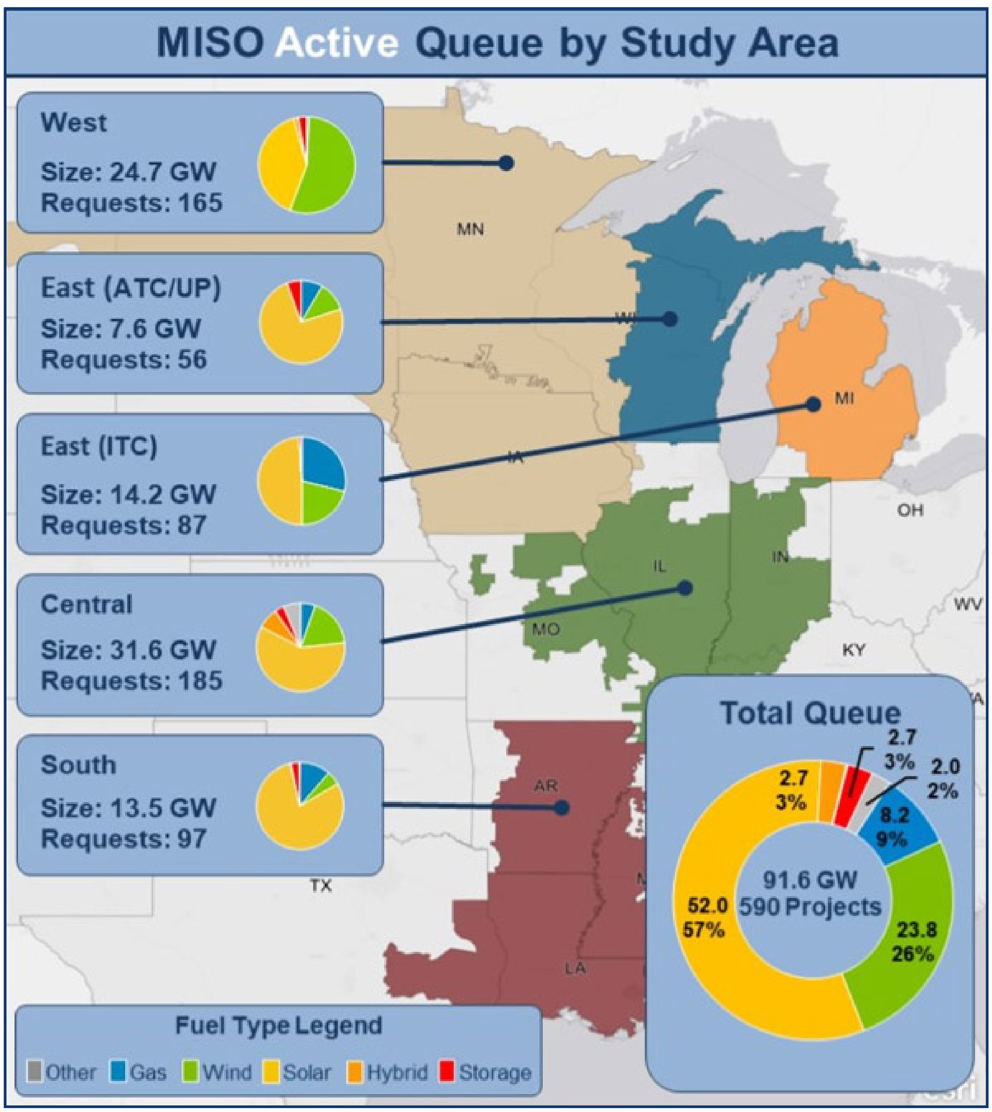
The RTO is targeting a refiling of the rule changes by early October, a few months later than originally anticipated. (See *MISO Makes Second Attempt at More Rigorous Queue*.)

The commission in March rejected the RTO's plan to impose more stringent site control requirements and increase milestone payments for interconnection customers, but it agreed the changes would reduce speculative and duplicative projects. (See *MISO Promises Refile on Stricter Queue Requirements*.)

Speaking Wednesday at a Planning Advisory Committee meeting, Resource Interconnection Planning Manager Neil Shah made clear that the proposal is no longer up for debate. He began his presentation on the plan with an anecdote about a fixed-price, no-haggle experience at a car dealership.

"So, me, in front of you, I feel like that" car salesperson, he joked.

Shah said MISO's queue is in dire need of the firmer site control requirements and milestone fees outlined in the plan, adding that a large volume of unready projects translates into inflated costs and cost volatility for other queued projects. The queue now includes 590 projects totaling about 92 GW after hovering around 100 GW for most of this year. In the last three years, about 800 projects comprising about 120 GW have entered the queue.



MISO interconnection queue September 2019 | *MISO*

"We've seen projects with power purchase agreements, projects with provisional [generator interconnection agreements] forced to withdraw because of high costs," he said.

Shah pointed to the February 2017 cycle of projects entering the queue as an example. Of 27 projects at 3.4 GW joining the queue, only two at 250 MW cleared. As a result, the MISO system went from requiring an estimated $3.4 billion in network upgrades to not needing a single one.

While the penalty-free "off-ramps" incorporated into the queue in 2017 are working as intended, MISO still needs a means to discourage unprepared project owners from prematurely lining up for interconnection in the first place, Shah said.

"It still needs adjustment up front," he said.

MISO's proposal would require developers of proposed generating facilities to demonstrate site control 90 days before a project enters the first phase of the three-phase definitive planning phase (DPP). It would also eliminate the RTO's current practice of accepting a $100,000 deposit in lieu of proof of site control.

The refiled plan will no longer seek changes to the queue's first milestone payment, which will remain $4,000/MW instead of becoming a variable cost representing 10% of the average network upgrade costs from the last three DPP cycles. The new plan will also add a refund mechanism to the total milestone fees imposed on a customer. The "true down" feature would cap total milestones at 20% of a project's network upgrade cost, with any excess payment refunded back to interconnection customers after a project clears the second decision point, roughly 220 days into the queue.

As with MISO's first filing, 50% of milestone fees would be considered at risk of not being refunded if they're needed to help defray network upgrade costs should a project withdraw.

Additionally, MISO will now allow different fuel types and multiple generation projects to share the same site, scrapping the first proposal's requirement that project owners show exclusive use of land. ■

Key Details Change in MISO MEP Cost Allocation Plan

By Amanda Durish Cook

CARMEL, Ind. — Months after FERC rejected an earlier cost allocation plan, MISO is circulating a new draft proposal that would further lower voltage thresholds but raise cost minimums on economically beneficial transmission projects.

Under the new *plan*, MISO would lower the voltage requirements on market efficiency projects (MEPs) from 345 kV to 100 kV, compared with the 230-kV minimum in the first filing.

However, the cost threshold is set to rise from $5 million to $25 million for regional MEPs.

For interregional MEPs with either SPP or PJM, MISO will also seek a 100-kV voltage threshold but no cost threshold.

Jesse Moser, MISO | © *RTO Insider*

"Perfection is not achievable, but we want to be as good as we can be," Jesse Moser, MISO director of economic and policy planning, said during a meeting of the Regional Expansion Criteria and Benefits Working Group (RECB-WG) on Thursday.

Moser said the cost requirement increase maintains a "demarcation of larger, regionally beneficial projects." MISO's $5 million threshold was approved by FERC in 2007.

The $25 million figure is not final and still open to suggestion, Moser said. He said a regional MEP cost threshold could also be designed to move with inflation. Going forward, MISO intends to review its MEP cost allocation method with stakeholders once every three years, he said.

"It was more about having a way to have some separation between local and regionally economic projects," Moser said. "There's not going to be an answer that doesn't have some controversy and challenges."

As in the first filing, the new plan would exempt from MISO's competitive bidding process any MEPs needed within three years to mitigate reliability issues. The filing also preserves the elimination of a 20% postage stamp cost allocation. It additionally still seeks to add new benefit metrics for savings from the avoided costs for reliability projects and cost reductions related to the MISO-SPP transmission contract path.

But the new filing has abandoned a provision that would create a local economic project type.

FERC rejected the first cost allocation filing in June, finding it would have violated the principle of cost causation because projects proposed under the local economic transmission category would be required to demonstrate regional benefits while only being cost-shared on a local level.

The project type was meant for smaller, economically driven transmission projects between 100 and 230 kV, with 100% of costs to be allocated to the local transmission pricing zone containing the line. The projects would not only have to meet a local benefit-to-cost ratio of 1.25-to-1 or greater within their pricing zones but also be required to show the same minimum regional 1.25-to-1 ratio required of MEPs. (See *MISO Mulling Next Steps on Cost Allocation Overhaul*.)

"While FERC expressed appreciation for many aspects of the proposal, the commission had some concerns about the newly created local economic project category," MISO CEO John Bear said at the RTO's July Informational Forum.

Discord

MISO considered several possibilities before settling on the draft proposal, including lowering the voltage threshold to 100 kV for interregional MEPs only or placing projects lower than 230 kV back into the RTO's existing "other" project category. Stakeholders have offered various opinions on the refiling, with some urging MISO to lower the interregional voltage threshold to 100 kV on both sides of the seam, and others advising that any 100-kV project be eligible for regional cost-sharing.

"This seems simpler than some of the earlier discussions," Clean Grid Alliance's Natalie McIntire said of the new version at the RECBWG meeting.

However, other stakeholders contended the MISO community was suffering from "cost allocation fatigue." Some said it wasn't clear why the RTO so dramatically altered its original proposal to include 100-kV projects instead of simply removing the lower-voltage project issues FERC raised.

Xcel Energy's Susan Rossi characterized the proposal as a "drastic change at the last minute."

But others said that if MISO failed to address the lower-voltage cost-sharing, it would be ignoring LS Power's pending complaint that asks FERC to compel MISO to lower the threshold for competitively bid transmission projects from 345 kV to 100 kV. (See *Complaint Seeks Bigger Role for Smaller MISO Projects*.)

McIntire also said some stakeholders were forgetting that the original proposed 230-kV threshold was just the product of a compromise that several stakeholders still disagreed with because they felt it still represented too high a bar.

"I think MISO's decision to move to 100 kV throws that compromise out the window, and that will be evident to FERC," Entergy's Matt Brown contended.

2020 Extension

The new MEP filing will still contain a cost allocation proposal for interregional projects with PJM, even though FERC's rejection of MISO's first allocation plan stood to complicate separate deadlines associated with compliance around the longstanding complaint by Northern Indiana Public Service Co. (See "Interregional Filings Also Rejected," *MISO Allocation Plan Fails on Local Project Treatment*.)

FERC in mid-September granted an extension that will allow MISO to file its interregional allocation compliance by Jan. 2, 2020, instead of the original late September deadline (*EL13-88*). MISO was originally due to file its PJM interregional cost-sharing plan by Sept. 23, the date established in FERC orders stemming from NIPSCO's 2013 complaint over the PJM-MISO seam that ultimately eliminated a cost minimum and lowered the voltage threshold for MISO-PJM interregional projects to 100 kV.

MISO said it needed the extra time for the MEP filing "to ensure proper coordination" with the compliance filing ordered in the NIPSCO complaint. The RTO also said that this is its first extension request since FERC rejected its proposed cost allocation changes to interregional and regional MEPs.

At a Sept. 17 meeting of the MISO board's System Planning Committee, Director Nancy Lange urged stakeholders to keep working on a cost allocation refiling and remain undeterred by FERC's rejection of the first proposal.

"I was happy that there was a consensus that could be filed with FERC," Lange said of MISO's first filing in late February.

Moser said MISO doesn't envision using all the extension period granted in the NIPSCO complaint and hopes to make a revised cost allocation filing before Thanksgiving. MISO's latest proposal is open to stakeholder comment through Oct. 10. ■

NYISO News

NYISO Management Committee Briefs

2019 Summer Peak Load Falls Below 50/50 Forecast

The New York Control Area summer peak load of 30,397 MW on July 20 fell below the 50/50 projection for the sixth consecutive summer, Operations Vice President Wes Yeomans told the Management Committee on Wednesday.

The summer 2019 50/50 forecast was 32,382 MW, while actual peak load last summer was 31,861 MW.

"Things were relatively easy for the NYISO this summer, operationally speaking, with two heat waves, on July 18-21 and July 29-30," Yeomans said. He noted there were four days with peak loads over 30,000 MW.

"We did go into this summer knowing this was the last summer we'd have six nuclear plants," he said, referring to next spring's phased shutdown of the first of the two reactors at Indian Point, with the second unit to be decommissioned in 2021.

Yeomans noted that NYISO termed the July 29-30 period as "hot weather operations" on his *slides*, as the heat has to last three days to be classified a heat wave.

NYISO recorded the all-time peak for a Sunday on July 21 at 30,339 MW and met reliability criteria with surplus operating margins, with no emergency activations and no need for statewide supplemental capacity commitments, he said.

"Prior to July 18, transmission owners rescheduled a lot of their transmission work in anticipation of the heat wave," Yeomans said. "And it was hot, with heat indexes as high as 110 degrees [Fahrenheit] over the weekend [July 18-21]."

Daily mean temperatures were above the 20-year average in July, near average in June and August, and below average in May, with Albany posting 12 days with highs above 90 F.

Staff Transitions

CEO Rich Dewey mentioned a couple of "public service announcements," saying the NYISO Board of Directors' search is underway to fill the upcoming vacancy of Robert Hiney, who is set to leave in April 2020.

The board also approved the appointment of Robb Pike as vice president of market operations, Dewey said. Pike worked for NYISO's legacy organization, the New York Power Pool, and moved to the ISO at its inception in 1999.

Parallel Testing of EMS/BMS

NYISO hopes to go live with a new energy management system (EMS) and business management system (BMS) at the end of October and is operating a parallel testing phase through Oct. 7.

"That application is receiving all the telemetry that our legacy system is receiving and is doing everything but sending dispatch signals," Chief Information Officer Doug Chapman said.

The testing is an important phase, with EMS/BMS "running pretty well" except for a few issues that need to be resolved with vendor ABB before going live in October, he said.

If NYISO decides to proceed with the new EMS/BMS, it will move into parallel operations for two weeks in mid-October, double-staffing the control room, Chapman said.

The cutover date is currently targeted for Oct. 22. NYISO's last opportunity to switch to EMS/BMS in 2019 will be Oct. 31, which is the latest NYISO can cut over to the new system and still issue a necessary System and Organization Controls report to stakeholders by the deadline of Jan. 15, 2020.

"If we miss, the next opportunity to go live is March 1, and that delay has cascading impacts to our 2020 plans," Chapman said.

The ISO also is replacing the tool used to model the electric system, he said.

Draft 2020 Budget

Alan Ackerman, of Customized Energy Solutions and chair of the Budget and Priorities Working Group, delivered budget *highlights*.

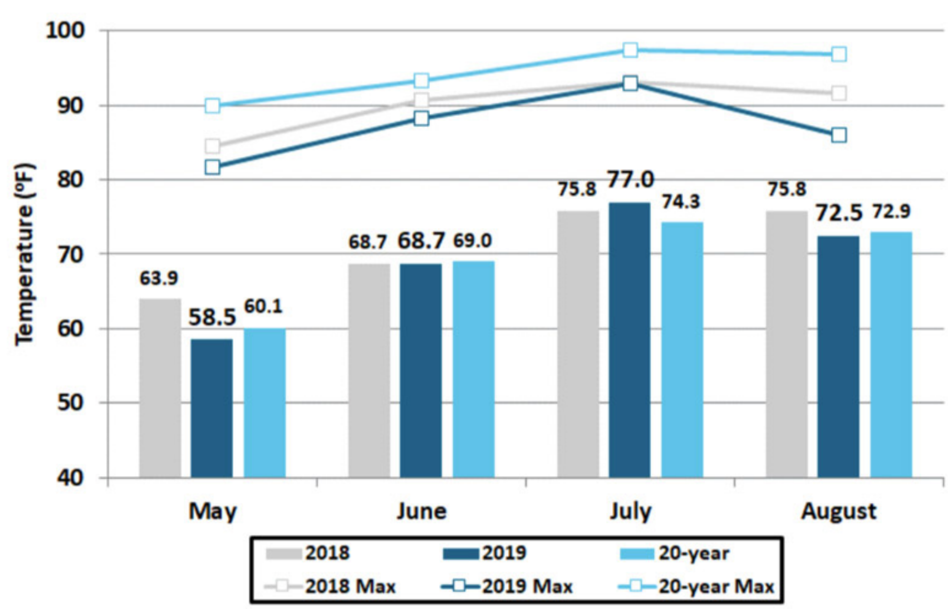
NYISO's draft 2020 budget totals $168 million allocated across a forecast of 154.3 million MWh, for a Rate Schedule 1 charge of $1.089/MWh. Comparatively, the 2019 budget was $168.2 million allocated across 157.1 million MWh for a Rate Schedule 1 charge of $1.071/MWh.

The draft budget would represent a 0.12% decrease in revenue requirement from 2019 and a 1.78% decrease in projected megawatt-hours, for an overall Rate Schedule 1 increase of 1.66%.

Cost avoidance is the main strategy behind keeping the ISO's budget flat for the fourth year in a row, according to the presentation, with salaries and benefits increasing $500,000 from this year, but employee health insurance plan changes effective for the 2020 plan year projected to avoid additional ISO cost increases of $400,000.

The board will review the draft budget in October ahead of an MC vote on it at the end of the month. The budget will then go to the board for approval at its Nov. 19 meeting. ■

— Michael Kuser



Monthly average and max temperatures for 2018, 2019 and 20-year (1999-2018) | *NYISO*

PJM News

PJM Monitor: Fix DR Capacity Seller Rules

By Christen Smith

PJM's Independent Market Monitor said the RTO should resume its efforts to close loopholes that allow demand response resources to sell high and buy low in its capacity auctions.

In an *analysis* published last month, the Monitor concluded that DR sellers bought the highest amount of replacement capacity between 2007 and 2019 — more than internal or external generation sources, both in and out of service, and energy efficiency resources. The Monitor said that statistics support its conclusion that DR market sellers base their offers on speculation, at best, and later buy replacement capacity for a "substantial portion" of those commitments at a discounted price.

"There is no reason for further delay on this matter," the Monitor wrote. "The evidence has been and continues to be quite clear. The incentives have been and continue to be quite clear. The lack of an enforced specific requirement that all capacity resources be demonstrably specific physical assets when offered into PJM capacity auctions continues to provide strong incentives to offer speculative paper capacity."

According to the Monitor's analysis, which focused on June 1 of each year, the share of net replacement capacity for DR commitments exceeded 50% from 2009 to 2011. Between 2012 and 2019, the rate exceeded 20%.
The Monitor attributed the decline to PJM's

	All Capacity Resources	Generation	Internal Generation	Internal Generation in Service	Internal Generation Not in Service	External Generation	Demand Resources	Energy Efficiency Resources
01-Jun-07	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
01-Jun-08	(0.6%)	(0.6%)	(0.6%)	(0.6%)	(7.7%)	(0.7%)	(7.2%)	
01-Jun-09	(1.5%)	(1.2%)	(1.4%)	(1.6%)	41.8%	13.6%	(53.2%)	
01-Jun-10	(3.1%)	(2.8%)	(2.6%)	(2.6%)	(6.1%)	(10.2%)	(53.6%)	
01-Jun-11	(5.0%)	(4.3%)	(4.3%)	(3.8%)	(29.0%)	(0.8%)	(57.6%)	0.3%
01-Jun-12	(6.7%)	(5.4%)	(5.4%)	(5.5%)	2.2%	(8.1%)	(25.8%)	(5.2%)
01-Jun-13	(7.7%)	(6.1%)	(5.9%)	(5.7%)	(11.9%)	(19.7%)	(30.7%)	13.3%
01-Jun-14	(8.4%)	(4.9%)	(4.4%)	(4.6%)	0.8%	(22.1%)	(45.0%)	19.0%
01-Jun-15	(6.8%)	(4.7%)	(5.0%)	(4.6%)	(15.8%)	3.0%	(31.3%)	28.2%
01-Jun-16	(9.0%)	(6.9%)	(5.4%)	(4.2%)	(25.7%)	(37.9%)	(36.2%)	3.5%
01-Jun-17	(7.7%)	(6.2%)	(6.2%)	(4.0%)	(30.7%)	(5.3%)	(32.6%)	10.2%
01-Jun-18	(6.9%)	(5.6%)	(5.3%)	(3.1%)	(26.5%)	(17.0%)	(27.8%)	10.8%
01-Jun-19	(6.9%)	(6.2%)	(6.0%)	(6.2%)	(4.4%)	(15.8%)	(20.0%)	(2.0%)

Net replacements to cleared capacity by resource classification: June 1, 2007, to June 1, 2019. | *Monitoring Analytics*

	All Capacity Resources	Generation	Internal Generation	Internal Generation in Service	Internal Generation Not in Service	External Generation	Demand Resources	Energy Efficiency Resources
01-Jun-07	(0.1%)	(0.1%)	(0.1%)	(0.1%)	0.0%	0.0%	0.0%	
01-Jun-08	(2.0%)	(2.0%)	(2.0%)	(2.0%)	(7.7%)	(1.3%)	(9.8%)	
01-Jun-09	(4.0%)	(3.7%)	(3.6%)	(3.5%)	(4.8%)	(12.5%)	(56.6%)	
01-Jun-10	(5.3%)	(5.0%)	(4.8%)	(4.8%)	(6.2%)	(12.1%)	(55.6%)	
01-Jun-11	(8.1%)	(7.3%)	(7.2%)	(6.8%)	(29.4%)	(13.1%)	(63.7%)	(1.0%)
01-Jun-12	(12.5%)	(10.4%)	(10.3%)	(10.4%)	(3.4%)	(19.2%)	(44.2%)	(25.2%)
01-Jun-13	(13.4%)	(8.8%)	(8.6%)	(8.5%)	(12.5%)	(21.4%)	(71.8%)	(70.4%)
01-Jun-14	(13.6%)	(8.2%)	(7.5%)	(7.5%)	(7.2%)	(36.8%)	(62.3%)	(64.9%)
01-Jun-15	(10.7%)	(6.9%)	(6.9%)	(6.5%)	(17.4%)	(6.8%)	(47.0%)	(39.5%)
01-Jun-16	(14.8%)	(10.9%)	(8.9%)	(7.8%)	(26.1%)	(52.9%)	(54.4%)	(77.8%)
01-Jun-17	(12.5%)	(9.9%)	(9.4%)	(7.2%)	(34.0%)	(24.8%)	(45.4%)	(37.6%)
01-Jun-18	(14.3%)	(12.3%)	(11.9%)	(9.6%)	(33.8%)	(25.0%)	(36.8%)	(45.1%)
01-Jun-19	(12.4%)	(10.5%)	(10.4%)	(10.6%)	(8.1%)	(16.4%)	(35.2%)	(41.9%)

Total replacements to cleared capacity by resource classification: June 1, 2007, to June 1, 2019. | *Monitoring Analytics* discontinuation of the Interruptible Load for Reliability (ILR) program.

In 2014, PJM implemented a rule that required DR sellers to submit a plan ahead of the capacity auction, but the Monitor said that didn't go far enough. Under existing rules, sellers must only provide site-specific and customer-specific information if their resources are located within a zone of concern that is also in excess of a curtailment service provider's (CSP) defined sell threshold. Only three zones of concern have been identified — ATSI, Penelec and MetEd — for delivery years 2017/18 through 2022/23.

The Monitor said that without identified customers or clear plans for implementing DR, CSPs can make speculative offers in the Base Residual Auction that do not represent what may be physically available during the actual delivery year.

"The risks to the markets associated with the sale of DR without any supporting information on the plausibility of the underlying assets include the risk that multiple CSPs could be assuming that they will win the same customers and the risk that sellers are taking speculative positions with a low probability of fulfilling them," the Monitor wrote. "The result in both cases is that the system is less reliable than it might otherwise be because the full amount of DR that cleared the [Reliability Pricing Model] auction is not actually available, the price to other capacity resources has been suppressed by the sale of the speculative DR, new entry of other capacity resources could have been forestalled by the sale of speculative DR, and there may not be adequate replacement resources available with short notice prior to the delivery year."

The Monitor said physical generation assets become displaced in the BRA and then have an incentive to offer at lower prices in the Incremental Auctions to recover capacity revenues. Those lower prices permit the buyback of "speculative DR" at lower prices, encouraging the bidding cycle to continue and "creating an unfair advantage … and self-fulfilling dynamic that incents more of the same behavior."

The problem hasn't been lost on PJM. The RTO filed Tariff revisions in 2014 to address the issue, but FERC rejected the filing and initiated a proceeding under Section 206 of the Federal Power Act and held technical conference to sort the problem out. In August of that same year, PJM stalled the proceeding in order to collect additional data under its new Capacity Performance construct. In 2018, PJM filed Tariff revisions for its IA procedures in tandem with another deferral on its earlier capacity replacement docket. FERC rejected the auction Tariff filing and terminated the 2014 docket, leaving the issue unresolved.

PJM is reviewing the Monitor's report, spokesman Jeff Shields told *RTO Insider* on Wednesday.

"The IMM is correct that PJM has taken steps to further solidify the requirements for demand response to substantiate its physical nature as part of the DR sell offer plans, and additional PJM proposals in this regard have been rejected by FERC. PJM would need to evaluate whether further restrictions are appropriate," Shields said.

The Monitor urged PJM to pick back up with the docket and change existing rules so that DR sellers must provide evidence of physical commitment from specific and identified customers in the form of a contract signed six months prior to the appropriate capacity auction. It also encouraged limiting replacement capacity transactions to those resources with physical issues. ■

PJM Suspends Auction Deadlines Pending FERC Action

Storage Changes also in Limbo

By Christen Smith

VALLEY FORGE, Pa. — PJM told its Markets and Reliability Committee on Thursday that all deadlines for upcoming capacity auctions will be suspended pending FERC action on the RTO's proposed revisions to its capacity market.

The news follows Commissioner Richard Glick's disclosure that he will recuse himself from any matters involving his former employer, Avangrid, until Nov. 29, after FERC's designated agency ethics official changed his interpretation of an ethics pledge signed by all presidential appointees under an order from President Trump. Avangrid has filed comments and testimony in the case, and Glick has indicated he won't seek a waiver. (See *Glick Recusal May Mean No MOPR Ruling Before December*.)

PJM had anticipated commission action before the end of year, when many deadlines for the 2023/24 Base Residual Auction would come due. (See "Capacity Auction Ruling Anticipated Before 2020," *PJM MIC Briefs: Aug. 7, 2019*.)

In July, FERC halted the 2022/23 capacity auction scheduled for August, refusing to "rule prematurely" on PJM's request for clarification that if it ran the BRA using the existing minimum offer price rule that the commission would also agree to enforce any new rates prospectively, saving the auction from being rerun (EL16-49). (See *FERC Halts PJM Capacity Auction*.)

Jen Tribulski, PJM | *© RTO Insider*

"PJM is not going to run forward with any BRA-related deadlines until we receive a FERC order and can establish a timeline from that order," said Jen Tribulski, the RTO's associate general counsel. The suspension applies to all future delivery years, though PJM will continue running Incremental Auctions for all previously completed BRAs.

Glick's recusal also leaves the RTO's second Order 841 compliance filing (ER19-469) in limbo, said Andrew Levitt, PJM's senior business solution architect for applied innovation.

Andrew Levitt, PJM | *© RTO Insider*

Although Avangrid was not a party to PJM's compliance filing, Levitt said it's unclear whether Glick will sit out from issuing an order ahead of the filing's requested Dec. 3 implementation date.

Meanwhile, PJM *plans* to proceed with the multi-use, load-serving energy storage resource (ESR) settlement provisions approved in docket ER19-462. The pending changes detailed in docket ER19-469 — which deal with real-time and day-ahead market changes and billing related to charging ESRs that take transmission service — will be placed on hold. Instead, PJM will adhere to status quo rules, which allow ESRs to participate in all its markets and will count battery charging as "negative generation" that does not take transmission service. ■

PUCO Delays Ruling on AEP Solar Projects

By Christen Smith

PUCO's ruling on the need for two proposed AEP solar projects didn't come Thursday, as anticipated. | *Solar Energy Industries Association*

The Public Utilities Commission of Ohio last week delayed ruling on the need for two solar projects proposed by American Electric Power after the company asked for a "brief hold" to update its filings to reflect the impact of the recently approved Clean Air Act.

In its *request* filed Sept. 20, AEP said certain provisions of the new law — also known as House Bill 6 — convey potential benefits to the 300-MW Highland Solar and 100-MW Willowbrook facilities proposed in its long-term forecast report filed last year. The company offered very few details of how the legislation changes its proposal, citing confidentiality agreements, but did ask for a 60-day delay in proceedings.

"The new filing, if successful, would present the commission with additional options and flexibility as compared to the company's existing proposal filed in these proceedings," Steven Nourse, AEP's attorney, wrote in the request. "Moreover, it is the company's view that the new filing will ameliorate many of the concerns and objections raised by opponents in these proceedings. Such developments should be viewed as helpful regardless of whether the potential opinion and order scheduled for consideration on Wednesday would have initially rendered a positive finding or a negative finding on the need issues."

The $170 million Clean Air Act, signed into law in July, curtails the state's current renewable portfolio standards and tacks on monthly fees — ranging from 80 cents for residential customers to $2,400 for large industrial plants — to electricity bills, mostly for FirstEnergy Solutions' Davis-Besse and Perry nuclear facilities. Some $20 million of the fees collected will support six solar power projects, including Highland Solar and Willowbrook, in rural areas of the state. (See *Ohio Approves Nuke Subsidy*.)

AEP submitted documents last year seeking cost recovery under the state's renewable generation rider (RGR) for 500 MW of wind and the Highland and Willowbrook solar projects.

PUCO said last year that it would first determine the need for the projects before approving cost recovery mechanisms. On Sept. 19, the commission *indicated* it would announce a decision in the first half of the proceedings at its Thursday meeting; however, the agenda item was subsequently withdrawn. PUCO spokesperson Matt Schilling said the commission gave no reason for the change, telling *RTO Insider* that "it's not uncommon to pull cases from the agenda to allow for more time to consider."

Protesters — including the Ohio Consumers' Counsel, Direct Energy, IGS and IGS Solar — urged the commission to rule in the case anyway, calling the bill irrelevant to "the statutory issue of whether Ohio utility consumers need electricity from the proposed solar plants." *Kroger* and the *Ohio Coal Association* also opposed AEP's request.

"HB 6 did not alter Ohio law that strictly limits a utility's ability to seek PUCO approval of customer-funded subsidies for new generation plants that it proposes to own or operate," the protesters *wrote* in a joint filing. "This separate funding for a monopoly utility generation project (including solar) can only be approved by the PUCO if the utility can show, among other things, that utility consumers need the electricity from the proposed power plants. As has been shown in this case, Ohio consumers don't need electricity from AEP's proposed plants, as the competitive market provides more than an adequate supply of power."

The companies further allege that AEP doesn't need a second revenue stream on top of the money afforded to the projects via HB 6.

"An outcome that could actually 'ameliorate many of the concerns and objections raised by opponents in these proceedings,' as AEP asserts, would be for AEP to withdraw its proposal and to develop the contested renewable projects through a separate affiliate," the companies wrote. "Of course, AEP is free to undertake that endeavor outside this proceeding, without a delay in the PUCO's decision."

Scott Blake, an AEP spokesperson, told *RTO Insider* on Monday that concerns about the company collecting twice on the same projects presuppose the commission would accept the proposals as filed — an unlikely scenario given the impacts of HB 6 and the points raised by protesters within the proceeding.

"The HB 6 credit would also be factored in to any customer charge," he said. "Under the proposal, we would purchase power at a fixed cost per megawatt-hour from the developer of the project. The credit from HB 6 would be included in the cost and used to calculate the customer portion." ■

PJM News

PJM MRC/MC Briefs

CEO Search Continues

VALLEY FORGE, Pa. — Neil Smith, chairman of PJM's search committee and a member of its Board of Managers, told the Markets and Reliability Committee on Thursday that he anticipates former CEO Andy Ott's position will be filled by the end of fall.

"We are focused on speed but not at expense of quality," he said. "When we can share, we will."

Ott retired June 30 and board member Susan J. Riley stepped into his role temporarily while the organization searched for a replacement. (See *PJM CEO Andy Ott to Retire*.)

Non-retail BTM Generation Rules Endorsed

Stakeholders unanimously endorsed revisions to Manuals 13 and 14D to clarify the reporting, netting and operational requirements of non-retail behind-the-meter generation (NRBTMG). In Manual 13, maximum generation emergency actions and deploy-all-resource actions are identified as triggers to load NRBTMG.

The endorsement follows a one-month deferral requested by Exelon in order to review applying the rules to community solar programs and aggregate net energy metering. Both PJM and Exelon told the Operating Committee on Sept. 10 that compromise language was close to being finalized, which excluded both types from reporting requirements. (See "Non-retail BTM Generation Update," *PJM OC Briefs: Sept. 10, 2019*.)

PJM's Terry Esterly said Thursday that staff

Terry Esterly, PJM | © *RTO Insider*

added the revisions to Manual 14 Appendix D and Manual 28.

Stakeholders Urge Consensus on Load Management Testing Requirements

Stakeholders urged PJM and Enel X to reach a compromise on their dueling proposals to update load management testing requirements before a scheduled vote at the October MRC meeting.

"I would encourage both parties to find common ground and present one proposal," said Adrien Ford of Old Dominion Electric Cooperative. "I think there's been a lot of progress, and I'm just hoping we can see just a little more movement."

The key differences between the two packages, endorsed at the Market Implementation Committee on Sept. 10, involve how much advance notice PJM provides to demand response resources before a test and procedures for retesting. (See *PJM Stakeholders Support More Realistic DR Testing*.) PJM *wants* testing procedures to more closely mimic reality and proposes a three-step notification system that gives resources first notice on the 21st of the month before, with additional alerts the day before and the morning before. Resources that fail would request a PJM-scheduled retest.

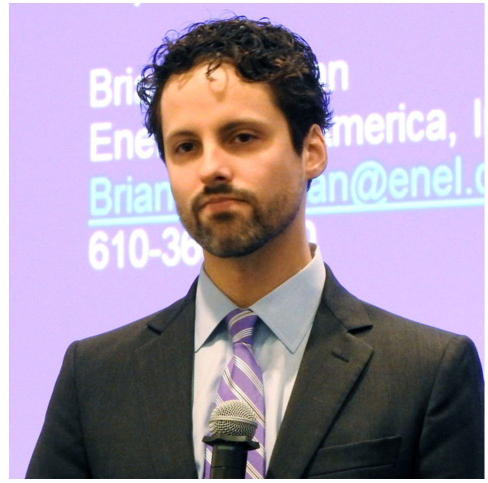
Enel X contends the month-ahead notification provides little useful information to resource owners who operate on a week-ahead timeline. It's also uncertain how PJM will manage retests when new rules would test resources seasonally — an ambiguity the Enel X *proposal* attempts to clear up.

"If you want to do a retest, how will you have time in a season to do a retest?" said Brian Kauffman of Enel X. "Since that could really determine the compensation for resources in a year, it's really important."

Susan Bruce, of the PJM Industrial Customer Coalition, said the RTO's proposal reads like a "gotcha test" to the companies she represents.

"We are not in a position to support PJM's package," she said, noting that consensus can still be reached. "I'm not looking to change testing for generators, but I note that there is an open-book test for generators, and there are many low-capacity-factor generators that similarly might not be operating a lot given our very healthy reserve margins."

Pete Langbein, PJM's manager of demand response operations, assured Bruce and others



Brian Kauffman, Enel X | © *RTO Insider*

that that wasn't staff's intention.

"The idea was not to have a gotcha test," he said. "We heard folks loud and clear, and what you have before you is dramatically different from what we started with. We agree it's not fair" to test without advance notice.

Independent Market Monitor Joe Bowring said PJM's package isn't rigorous enough.

"It's important to remember that demand response plays a critical role in PJM and a significant role in capacity markets. The PJM proposal is a very modest improvement, and of course you'd rather not have it because it imposes costs.

"While I appreciate your concerns, PJM's proposal is at the extreme end of modes and should be a very basic requirement for ensuring that demand response is actually there when we need it," he added.

If PJM and Enel X are unable to reach a compromise, the RTO's package will be considered first by the MRC. Enel X's proposal would only come to a vote if the PJM package fails to win approval.

Reserve Requirement Study Preliminary Results

PJM said preliminary *results* for its 2019 reserve requirement study lowered both the installed reserve margin (IRM) and forecast pool requirement (FPR), which will reset key parameters for the RTO's upcoming capacity auctions.

Patricio Rocha Garrido, of PJM's resource adequacy planning department, said the 2019

PJM News

capacity model, the 2019 load model and the 2019 capacity benefit of ties (CBOT) drove the nearly 1% decrease in IRM, though the capacity model didn't impact the lowered FPR.

The final report will be distributed Oct. 8 and include recommended IRM and FPR for delivery years 2020/21 through 2023/24.

Manual 34 Changes

The MRC and Members Committee also approved by acclimation changes to Manual 34: PJM Stakeholder Process addressing the prioritization of issues and creating an alternative path for critical, time-sensitive issues. The changes are also intended to ensure transparency throughout the process. (See *New Rules to Give PJM Members More Time on Issues*.)

PJM's Markets and Reliability Committee and Members Committee met Sept. 26 in Valley Forge, Pa. | © *RTO Insider*

The MRC also endorsed changes to the following manuals:

- *Manual 11*: Energy & Ancillary Services. The revisions document the procedure for addressing missing historical performance scores in the regulation market and clarify that the reserve requirements used in the market clearing process are based on the largest single contingencies that are communicated by PJM Operations and modeled in the markets clearing software.
- *Manual 15*: Cost Development Guidelines. To comply with FERC Order 841, changes were made to language on hydro resources and flywheels. Definitions were added for efficiency factor, fuel cost, variable operations and maintenance (VOM) and ancillary service costs. It was also approved by the Members Committee.
- *Manual 27*: Open Access Transmission Tariff Accounting and *Manual 28*: Operating Agreement Accounting. The changes, required to comply with FERC Order 841, detail PJM settlement procedures for "charging energy," which is purchased by energy storage resources for later resale. Charging energy is always billed at the applicable LMP, but different categories of charging energy are subject to different sets of charges. They include "direct charging energy" — power purchased by a storage resource from the PJM energy market for later resales to the market or is lost to conversion inefficiencies — and "load-serving charging energy," which is purchased from the energy market and stored for later resale to end-use load. ■

— Christen Smith

Company Briefs

Duke Announces 2nd PPA for Frontier Windpower II

Duke Energy Renewables has lined up a second major purchaser for its Frontier Windpower project in Kay County, Okla., as AT&T signed a 15-year, 160-MW virtual power purchase agreement with it.

Earlier this year, Duke announced that Ball Corp. had signed the same type of 15-year agreement. The earlier agreement accounts for 161 MW of Frontier Windpower II's 350-MW capacity.

"We're pleased to be working with AT&T and Ball Corp. on the Frontier II project, which will be located in an area that has some of the best wind resources in the country," said Rob Caldwell, president of Duke Energy Renewables.

More: *The Oklahoman*

DTE Sets Goal of 100% Carbon Neutrality by 2050

DTE Energy said it is committing to achieve net carbon neutrality by 2050.

"We're going to work on technological advances that we see coming in the future," said Trevor Lauer, president and COO for DTE Electric. "Things like carbon capture and sequestration, storage technologies, and even advanced modular nuclear."

More: *Michigan Radio*

Honda to Acquire 320 MW of Renewables in 2 Virtual PPAs

Honda has clinched the car industry's supposedly "largest" renewable energy deal, signing a duo of virtual power purchase agreements for 320 MW of wind and solar to power its U.S. operations.

The agreements, which cover 120 MW of wind from an Oklahoma farm being developed by E.ON and 200 MW of solar from Texas, will offset 1.012 million MWh of fossil fuel-powered electricity currently generated by the carmaker annually.

Honda will purchase 482,000 MWh each year from an under-construction solar facility in Texas, starting in the autumn of 2021. The specifics of the project will be shared in 2020, according to Honda. The firm will start purchasing wind power from E.ON next fall.

More: *PV-Tech*

Federal Briefs

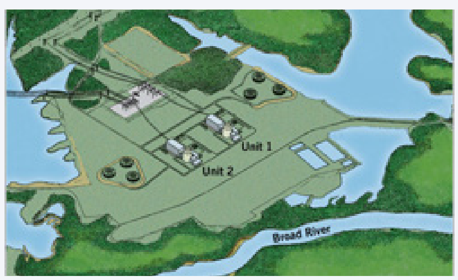
House Subcommittee Approves Yucca Mountain Bill

The House Energy and Commerce Committee's Subcommittee on Environment and Climate Change passed a bill last week that would allow the Department of Energy to undertake "infrastructure activities" for operation of Yucca Mountain as a radioactive waste repository. The bill, sponsored by Reps. Jerry McNerney (D-Calif.) and John Shimkus (R-Ill.), now goes to the full committee.

The legislation may have a tough time getting through. Funding proposed by the Trump administration to continue the licensing process needed for a construction permit for Yucca Mountain was stripped from a House appropriations bill earlier this year, while Nevada's congressional delegation has opposed funding the project.

More: *Las Vegas Review-Journal*

Duke Gets OK to Recover $258M Spent on Nixed Nuclear Project



FERC has cleared Duke Energy Carolinas to recover roughly $258 million in costs associated with the cancelled Lee Nuclear Station project in South Carolina under an amortization plan that veers from the commission's normal policy.

The proposed cost recovery methods were "a reasonable compromise that provide savings to the wholesale customers ... and result in a reasonable sharing of the canceled" project's costs among those customers, FERC said (*ER19-2468*).

The requested recovery of 50% of prudently incurred costs for the nuclear project's development will be collected through wholesale formula rates of 14 power purchase agreements between Duke and its affected wholesale customers.

More: *S&P Global Platts*

Details on Perry's Role in Ukraine Scandal Sought by House Democrats

House Democrats who have opened an impeachment inquiry against President Trump want his attorney, Rudy Giuliani, to turn over documents related to Energy Secretary Rick Perry's involvement with Ukrainian leaders last spring.

Three committees investigating Trump issued a subpoena to Giuliani on Monday, looking for documents related to Perry's trip to Ukraine President Volodymyr Zelenskiy's May 20 inauguration and a May 23 White House meeting involving Perry, former Ambassador Kurt Volker "and/or" Ambassador Gordon Sondland. The subpoena also calls for any communications between Giuliani and Perry.

Perry's Ukraine trip was mentioned in the whistleblower complaint that sparked House Democrats' efforts to impeach Trump. According to the complaint, Perry was sent in place of Vice President Mike Pence to lead a U.S. delegation at Zelenskiy's inauguration. U.S. government officials allegedly told the whistleblower that Trump instructed Pence to cancel his planned trip to Ukraine, and it was "made clear" that Trump would not meet with Zelenskiy until he saw how Zelenskiy "chose to act" in office.

More: *Houston Chronicle*

State Briefs

CONNECTICUT

Letter from Legislators to Lamont Opposes Killingly Power Plant

A group of 26 state lawmakers last week signed a letter addressed to Gov. Ned Lamont opposing the construction of the gas-fired Killingly Energy Center.

The letter said that the plant would produce more than 2.2 million tons of carbon dioxide, which is equal to 5% of the state's greenhouse gas emissions. It also references Lamont's Executive Order 3, which set up a plan for the state to be able to produce 100% of its electricity without carbon emissions by 2040.

The project was approved by the Siting Council with a 4-1 vote. The council said the plant had a public benefit and is "not in conflict with the policies of the state concerning such effects and are not sufficient reason to deny the application."

More: *The Bulletin*

MASSACHUSETTS

Lawyers Propose Plan for $143M Gas Explosions Settlement

Roughly 175,000 residents and business owners could benefit from a $143 million class action settlement from last September's natural gas explosions in three Merrimack Valley communities.

The proposal to distribute proceeds from the settlement against Columbia Gas of Massachusetts calls for six categories of lump sum payouts, ranging from up to $50 for a "nominal" disruption to up to $15,000 for a "major" disruption. The proposal is subject to a judge's approval, and a court hearing is slated for Oct. 7. Columbia Gas, which has spent $1 billion in recovery and restoration efforts, said it supports the proposal.

The Sept. 13, 2018, disaster injured dozens of people and destroyed or damaged about 100 structures. Thousands of residents and businesses were also left without natural gas service for heat or hot water, in some cases for months.

More: *The Associated Press*

Lawrence Residents Return Home After 'Major' Gas Leak

Residents evacuated after a gas leak was detected in Lawrence, in the same area of the city hit by multiple gas explosions last year, were returning to their homes Friday afternoon, officials said.

"This is a different situation than what happened last year," said Mark Kempic, president of Columbia Gas. "This is not an over-pressurization situation. We've isolated the area. We installed critical valves last year that allowed us to isolate the area down to these 146 meters."

Lawrence Mayor Dan Rivera said the affected area was Andover Street to Merrimack Street and Sanborn Street to Parker Street. Rivera said most evacuated residents should be able to return to their homes Friday afternoon. There may be delays for residents in the South Broadway area to return to their homes, officials said.

More: *WMUR*

MICHIGAN

PSC Approves Rate Increase for Consumers Energy Gas Customers

The Public Service Commission last week approved a rate increase of $143.5 million for Consumers Energy gas customers. The increase will cost the average residential customer an extra $5.48/month, beginning in October.

Consumers is expected to increase gas transmission and distribution infrastructure investments, accelerate the removal of at-risk lines made of vintage materials, and enhance technology capabilities through metering and customer-facing applications for improved customer service.

When it filed its request in November 2018, Consumers sought an increase of $229 million in its retail rates for natural gas distribution over rates that were approved in August 2018. The utility later reduced the request to $204 million.

More: *Michigan PSC*

MINNESOTA

PUC Rejects Xcel's Purchase of Mankato Natural Gas Plant

The Public Utilities Commission last week rejected Xcel Energy's purchase of a natural gas power plant in Mankato, saying it was not in the public interest.

Xcel said it wanted to purchase the Mankato Energy Center to help with the utility's planned early retirement of coal plants in the state. But the state Department of Commerce, the Citizens Utility Board of Minnesota and others raised questions about the cost of the plant and said it could hurt the utility's customers.

"This purchase was not in customers' interest. For Xcel to spend $650 million of ratepayer dollars to purchase the plant would present too much cost and too much risk," CUB Executive Director Annie Levenson-Falk said.

More: *MPR News*

NEW YORK

NYC to Consider Norway-style Bill to Budget Emissions

The New York City Council is considering a bill that proposes to amend the administrative code to require the mayor's office to set an "emissions budget" and allot a limited volume of greenhouse gases to each agency and city-funded nonprofit. The budgets would be evaluated at the end of every fiscal year.

Buildings, wastewater treatment and vehicles make up the bulk of the city's government emissions, which fell 29% in the decade after 2007, but calls for new policies to cut emissions and adapt to climate change are mounting. According to Councilman Costa Constantinides, the bill would force city agencies to "think about these things on a yearly basis."

More: *HuffPost*

OKLAHOMA

PSO Reduces Customers' Bills to Account for Cheaper Natural Gas

Public Service Company of Oklahoma announced last week that it will be lowering customers' bills to account for cheaper natural gas in the state.

Utility officials said customers will see discounts ranging between 2.9 and 19.2%, and its average residential customer could expect their bill to drop by about $3.68.

"The reduction in the fuel cost adjustment is largely the result of continued lower prices for natural gas, which PSO uses to generate a substantial portion of the electricity used by our customers," said PSO's Matthew Horeled, its regulatory and finance vice president.

More: *The Oklahoman*

VERMONT

Burlington City Council Declares 'Climate Emergency'

The city of Burlington has joined dozens of other U.S. municipalities in declaring a climate emergency.

The declaration comes weeks after Mayor Miro Weinberger announced a plan to make Burlington a net-zero-energy city by 2030. The City Council voted 11-1 to pass two resolutions which both declare "climate emergencies." A climate emergency exists and "threatens our community, state, region, nation and planet, posing a threat to human health and safety, biodiversity and our common environment," one resolution said.

One resolution encourages all city departments to take steps to help ensure the city reach its net zero goal by 2030, and for city staff to present to the council by Jan. 6, 2020, on how each department will work on these efforts.

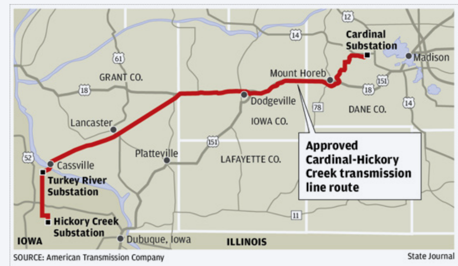
More: *VT Digger*

WISCONSIN

PSC Gives Final Approval to Cardinal-Hickory Creek

The Public Service Commission last week unanimously granted final approval of the Cardinal-Hickory Creek line between Dubuque, Iowa, and Middleton while rebuffing conflict of interest charges from opponents of the nearly $500 million project.

The project has been designated a multi-value project by MISO because it will enable the delivery of energy in support of reliabili-



SOURCE: American Transmission Company State Journal

ty, economic and renewable energy benefits. The estimated $492 million project will be cost-shared amongst users in MISO's footprint, with the cost to Wisconsin ratepayers being roughly $66 million. (See *Wisc. PSC Approves Cardinal-Hickory Creek Tx*.)

The commission rejected a call for recusal by the Driftless Area Land Conservancy and Wisconsin Wildlife Federation, which last week alleged real or perceived conflicts of interest by Chairwoman Rebecca Valcq and Commissioner Mike Huebsch, the latter of whom serves on MISO's Advisory Committee. In his role with MISO, Environmental Law & Policy Center attorneys argued, he had outside communications with a party to the case.

More: *Wisconsin State Journal*