RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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PG&E Restores Power amid Public Backlash

CEO Acknowledges Poor Performance

By Hudson Sangree

Pacific Gas and Electric restored power to 738,000 customers across central and Northern California over the weekend after its public safety power shutoffs (PSPS) and failed communications prompted a backlash from the public, state regulators and elected officials.

California Gov. Gavin Newsom backtracked on his earlier statements that the shutoffs were an appropriate means to prevent wildfires and said during a news conference last week that PG&E's neglect of its power lines had led to the massive intentional blackout of more than 2 million residents.

"This is not, from my perspective, a climate change story as much as a story about greed and mismanagement over the course of decades," the governor said Thursday during a press conference at the state's Office of Emergency Services near Sacramento.

Responding to criticism in his own news conference, PG&E Corp. CEO Bill Johnson acknowledged mistakes. The utility's website had crashed, its phone lines were overloaded and its shutoff maps were inconsistent if not incorrect, he said.

"To put it simply, we were not adequately prepared to support the operational event," Johnson said.

The CEO said the utility decided to shut off power in 34 counties based on its weather predictions but did not have the "granularity" needed to limit shutoffs to areas where they were most needed. He vowed the company would do better next time.

PG&E instituted the blackouts as part of

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RTO Responses Reveal Uneven Landscape for DERs

By RTO Insider Staff

Glendora, Calif., Sam's Club solar panels | *Walmart*

CAISO, ISO-NE and NYISO look to be the pacesetters in opening the country's organized electricity markets to greater participation by distributed energy resources, according to filings submitted to FERC on Oct. 7.

The filings came in response to the commission's request for information on how RTO/ISO interconnection processes accommodate aggregated DERs. (See *FERC Sends DER Data Request to RTOs*.)

In its Sept. 5 letter, which included 11 questions, FERC said it was seeking information in particular on distribution-connected DERs aggregated to participate in wholesale markets. The submissions provided a flavor of how disparate the treatment of DER aggregations across the markets is, an issue FERC will likely attempt to tackle in its rulemaking (RM18-9):

- CAISO, PJM, MISO and SPP said their interconnection processes do not differ based on whether the DER is a qualifying facility under the Public Utility Regulatory Policies Act. NYISO said QFs connecting to distribution facilities to participate in ISO markets are subject to the ISO's interconnection procedures, regardless of whether the distribution facility is subject to a FERC-jurisdictional

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In this week's issue

Counterflow

By Steve Huntoon

RMI and Pixie Dust, Round 4

By Steve Huntoon

To recap, environmental advocates have decided to fight natural gas generation, notwithstanding, as I've pointed out, the fundamental problems with relying only on renewables and batteries, and the fact that new natural gas, not renewables, is responsible for 90% of the reduction in carbon emissions in places like PJM.[1]

The latest salvo was Rocky Mountain Institute's claim that the bulk of new natural gas generation is/will be uneconomic. As I said before, perhaps the advocates hope that if gas investment is scared off, then renewables and batteries become a *fait accompli*.

RMI Study's Flaws Discussed in the Prior Column

My prior column[2] suggested RMI's study had at least two major flaws.

The first major flaw was that 40 to 50% of RMI's "clean energy portfolio" (CEP) comes from demand response and energy efficiency. It assumed large amounts of those resources are available at low cost.

And, importantly, it assumed that these hypothetical low-cost resources were only available to its renewables/battery CEP portfolio and not to a gas portfolio. As a result, the economics that RMI attributed to its renewables/battery portfolio actually came from mixing in low-cost DR and EE that are not unique to that portfolio.

The second major flaw was that in its modeling, RMI used traditional fossil generation to recharge the batteries. Yes, ironically, traditional fossil generation was supplying a "clean energy portfolio." And, most dramatically, in a last hour of covering peak load, the equivalent of a 1.5-GW gas generator was matched by: zero wind and a negligible amount of solar; batteries charged with traditional fossil generation; and huge amounts of DR and EE, neither of which are unique to a renewables/battery scenario. In other words, renewables contributed virtually nothing to matching the 1.5-GW gas generator.

RMI's Claims About Gas Investment

RMI replied to my column two weeks ago, adding new positions and defending its past ones. Let's see how it goes. (See *Stakeholder Soapbox: The Risky Case for Gas-fired Plants.*)

First, RMI claims that we're already seeing premature gas retirements, citing the retirement of one gas plant in California — which was due to the ill-fated GE H-Class turbine design[3] — and the bankruptcy of another in Texas — which was due to unique factors.[4] These one-off instances are not meaningful.

RMI says investors are "taking notice," pointing out that final investment decisions for new gas plants have declined since 2014. But at this level, they are the same as they were in 2010. Trend or cycle? And RMI is not correct that the capacity factor of combined cycle gas plants is declining; in fact, the article cited by RMI has a chart clearly showing the opposite.[5]

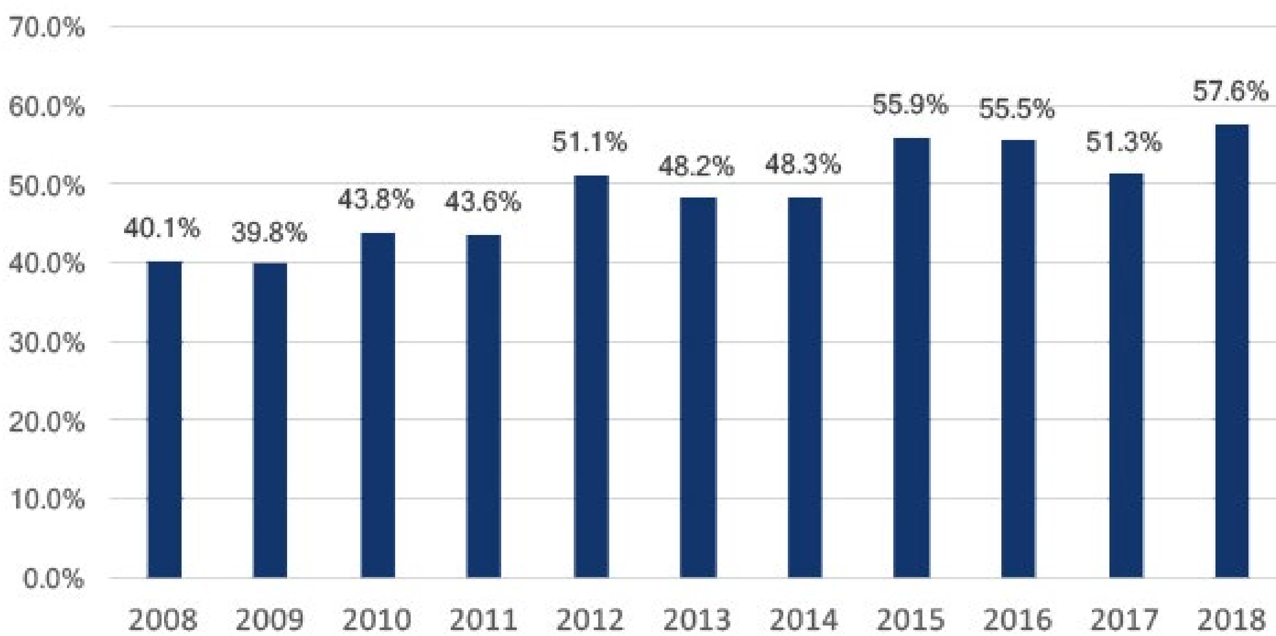
Just as Energy Information Administration data show that the capacity factor of combined cycle gas plants is at a record *high*.[6]

Even if RMI were right about such things as capacity factors, none of it is really reflective of investor sentiment. The real indicators are things like the share price of NRG Energy — the best proxy for competitive fossil generation (about half of which is gas) — which is up from $11/share to $40/share in the last three years. And RMI's own statement that there is "more than $100 billion in planned gas infrastructure investment through 2025."

If gas is a bad investment, Wall Street didn't get the memo. RMI may suggest its study is the memo, so that takes us back to the study itself.

RMI's Reply on Assuming and Co-opting the Low-cost Resources

RMI's aggressive assumption on lots of available DR and EE cannot be sustained by referring, as RMI does, to "definitive resource potential assessments" (my emphasis). Poten-



Natural gas combined cycle average annual capacity factors | *based on EIA data*

Counterflow

By Steve Huntoon

tial is just that.

But more important, RMI admits that it assumed the availability of (low-cost) DR and EE for its renewables/battery portfolio and not for its gas portfolio. It now says that's OK because its study showed that DR and EE are "natural complements to zero-marginal-cost generation from wind and solar."

I can't find anything in the study that remotely supports that proposition. I can't even find the words "complement" or "zero" in a word search. Please note that RMI saying in its study that it optimized resources in its modeling should not be confused with a showing that certain resources complement each other better than others.

Bottom line: The RMI study's co-option of low-cost DR and EE resources for its CEP portfolio is a fundamental, unsupported flaw.

Low-cost Resources Threat to Gas?

RMI says that the implication of my critique is that inexpensive DR and EE are themselves a threat to gas investment. A clever thought. But too clever by half. It's RMI, not me, that assumes vast availability of low-cost DR and EE.

And if DR and EE are a threat to gas, then they must be a bigger threat to more-expensive renewables. Is RMI warning Wall Street about renewable investment? No, I didn't think so.

The CEP Dependency on Fossil Generation

RMI does not deny that in the last hours of peak conditions, fossil units are providing needed generation via batteries, and renewables are providing virtually nothing. RMI says that just reflects the leveraging of available fossil generation for the foreseeable future.

Fair enough I guess. So long as everyone understands that RMI's modeling is not of a sustainable equilibrium condition. Instead, it depends on fossil generation sticking around so when solar and wind aren't generating, the system can still serve load reliably. And as I've pointed out, if new gas generation is scared off, then the old fossil with much higher carbon emissions will be what carries the CEP portfolio.

Finally, RMI goes on to overplay its hand by claiming that nothing undermines its central finding "that CEPs can compete and win on gas plants' own turf." No. In its modeling, RMI's CEP portfolio is undeniably dependent on fossil generation. RMI admits that. The converse is not true: A fossil fleet is dispatchable and is not dependent on renewables/batteries, as decades of reliability grid operation without renewables or batteries attest.

Yes, we'll still be needing that pixie dust. ■

[1] http://energy-counsel.com/docs/NRDC-Prescribes-More-Carbon-Emissions.pdf; http://energy-counsel.com/docs/Cue-the-Pixie-Dust.pdf.

[2] http://energy-counsel.com/docs/cue-more-pixie-dust.pdf.

[3] https://www.reuters.com/article/us-ge-power/general-electric-to-scrap-california-power-plant-20-years-early-idUSKCN1TM2MV.

[4] https://www.utilitydive.com/news/panda-temple-bankruptcy-could-chill-new-gas-plant-buildout-in-ercot-market/442582/.

[5] https://www.spglobal.com/marketintelligence/en/news-insights/trending/Pu5fAcJoqopojxYhGN0tMw2.

[6] EIA Electric Power Monthly, Table 6.7.A, for August 2019 and August 2014, available here: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

Stakeholder Soapbox

ERCOT 2019: Final Proof of a Successful Market Design?

By Rob Gramlich

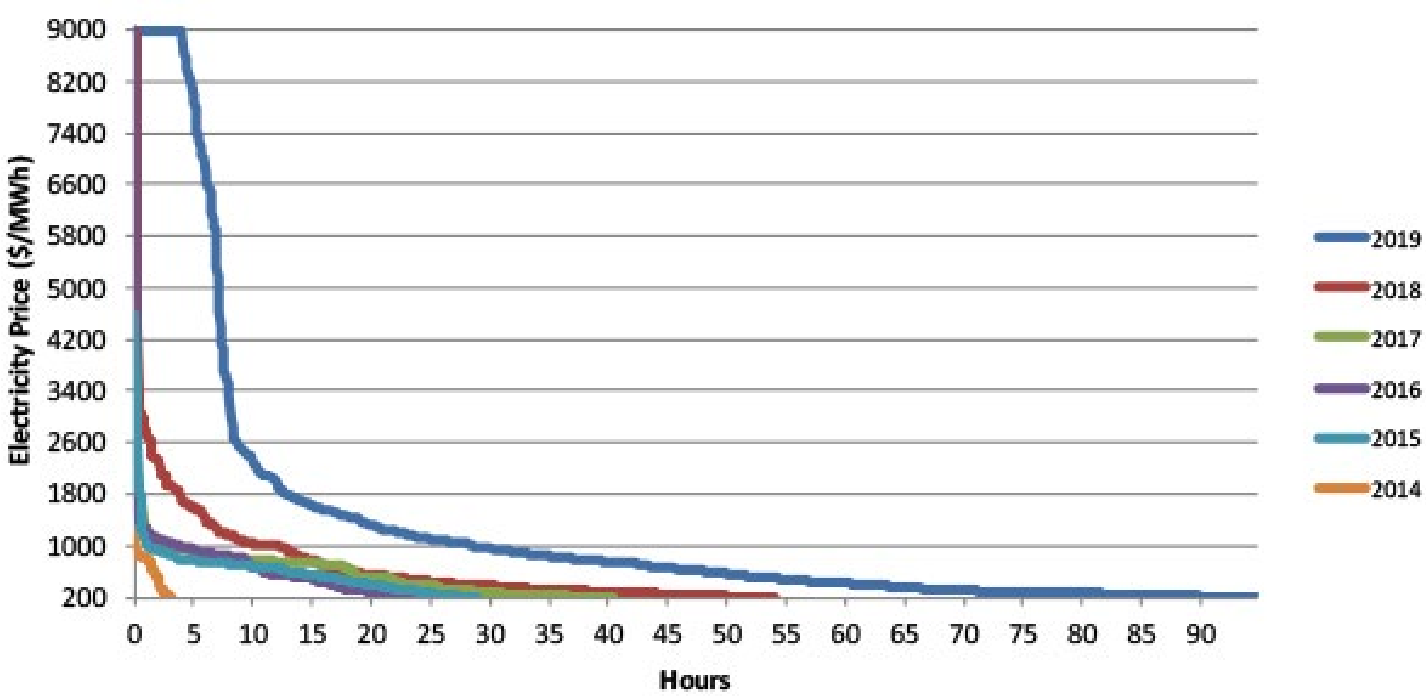
An important fall pastime, along with baseball playoffs, is to look back to see which electric market design model performed best over the summer. For the last several summers, a lot of eyes have been on the ERCOT market, given its relatively low reserve margins and lack of a mandatory forward capacity market. The results are in. There was no firm load shed because of supply shortages, and ERCOT's *2019 Summer Operational and Market Review* stated, "Overall, the market outcomes supported the reliability needs." My colleagues and I at Grid Strategies ran the revenue adequacy numbers and found that prices did what they should, providing appropriately strong signals to attract new market entry while charging customers only for what they needed.

The key distinction between ERCOT and regions with a capacity market or resource adequacy requirement is that in ERCOT, responsibility for assessing the level of supply and demand need for investment lies with market participants, not the grid operator itself. Other regions are charging customers more than 20% of the total cost of energy, capacity and ancillary services through capacity markets. In contrast, ERCOT focuses on grid operations more like an air traffic controller, saving consumers that money. It uses spot energy and reserves prices to accurately value energy over time and at each location, and lets market participants handle their own price risk management and supply assurance through bilateral contracts. Spot energy values at times of scarcity are allowed to reach $9000/MWh — reflective of true consumer valuation of supply at that time and place — and the value of reserves, which is based on a downward sloping operating reserve demand curve. By keeping dollars in spot markets as opposed to a capacity market, this market design attracts flexibility from demand response, storage, hydro and any other source that delivers when it is needed. There are no drawn out subjective debates with RTO management and stakeholders about what resources should count how much toward the elusive concept of "capacity," and what public policies should be mitigated, as is the case in the Northeast (see our *paper* showing how the minimum offer price rule costs PJM consumers $5.7 billion extra per year).

One would expect that when the system is low on capacity — as it was this summer with around an 8% reserve margin — prices would occasionally be very high and on average equal or exceed the amount that efficient new units need annually to recover their capital investment cost. In economic theory terms, in an efficient market at equilibrium, over the course of the year there would be enough "rent," or profit earned from prices that exceed generators' operating costs, that new generators see enough profit incentive to enter. So the question is, were prices over the last year high enough to attract and retain needed units? Our analysis below indicates the answer is YES.

Let's take a look at the prices in 2019 so far. (see our *blog* for data, assumptions and methodologies). The figure below uses ERCOT historical real-time ORDC data generated during each security-constrained economic dispatch interval to display the number of hours that prices have exceeded generators' operating cost from January through September.

As shown below, prices have been consistently higher this year than in previous years. So far, prices have already exceeded $200/MWh for 95 hours, with four hours and 10 minutes reaching the systemwide offer cap price. This September alone, with the most record-high temperature days since 2011, was responsible



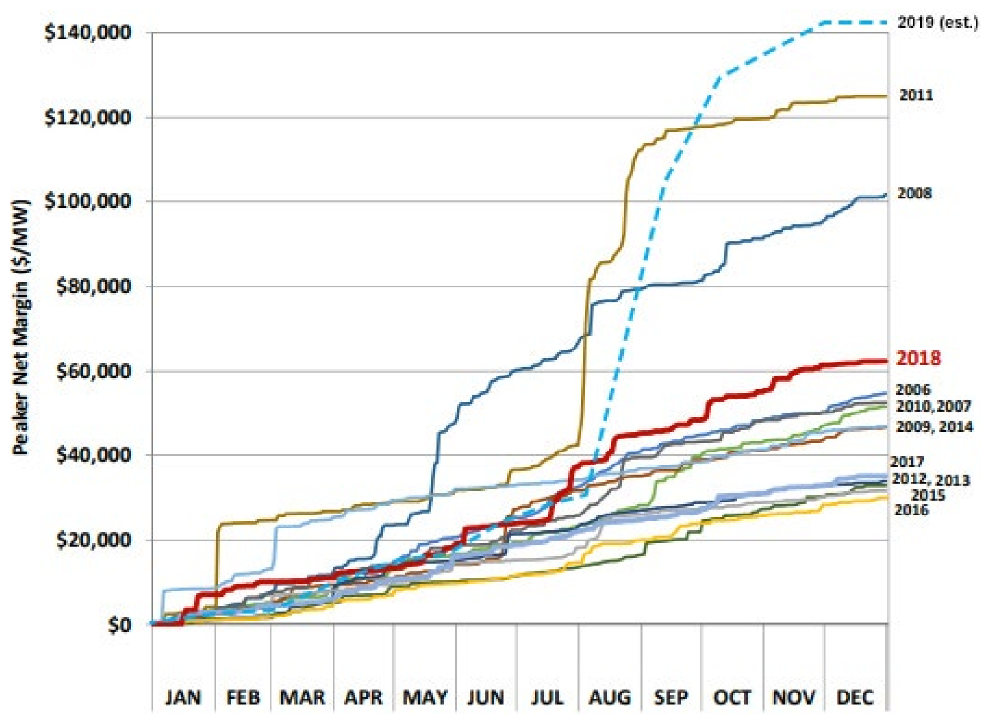
ERCOT price duration curve analysis (January to September) | *ERCOT*

Stakeholder Soapbox

for 10 minutes worth of prices at the offer cap and 20 hours worth of prices above $200/MWh. For reference, 2018 saw 54 hours over $200/MWh and only 10 minutes at the offer cap. Since the creation of the ORDC in June 2014, ERCOT only saw prices hit the offer cap one other time in 2016 for five minutes.

So prices have been higher, but were they high enough to attract entry? To answer that question, we can look at net margin for different units. In Grid Strategies' *analysis* of year-to-date data, efficient new peakers earned 35% above what they need to earn in an average year to pay for the capital cost of building the units, and combined cycle units earned 25% above that target. In most prior years when reserve margins were higher, they earned less than this target level.

These high spot prices signal to retail electric providers to go out and sign more contracts with generators so they can shield themselves from high spot market prices in the future. Those long-term power purchase agreements are then used by prospective generators to finance their new plants. An influx of 4,000 MW of solar and 5,000 MW of wind plants expected by next summer will likely take care of much of this need. Market participants also have clear responsibility and incentives to seek sources that shield them from high prices when wind and solar output is low. The Public Utility Commission of Texas reviews those entities' creditworthiness to make sure they are financially equipped to serve the load they commit to serve — an important and often forgotten regulatory responsibility of state commissions. Few customers actually had to pay the high spot prices, as they were covered by contracts signed well in advance, and the prices withstood the mild political opposition without regulatory intervention.



Peaker net margin analysis | *Potomac Economics*

This year may have been the best test to date of the ERCOT market design. The results so far indicate that despite the hot summer and low reserve margin, no firm load was shed because of supply shortages, while the system did provide sufficient price signals to attract and retain needed resources. High spot prices did not attract political intervention, and consumers only paid for what they needed.

ERCOT's 2019 experience should answer a lot of questions about whether ERCOT's unique market design works. One thing is for sure though: Our October pastime of reviewing the past summer's power market results will come again as surely as the sun rises or the baseball playoffs begin. ■

Rob Gramlich is founder and president of Grid Strategies LLC, a clean energy grid consulting firm.

RTO Responses Reveal Uneven Landscape for DERs

Continued from page 1

open access transmission tariff. ISO-NE said QFs selling all their output to the host utility follow state interconnection processes rather than the RTO's rules.

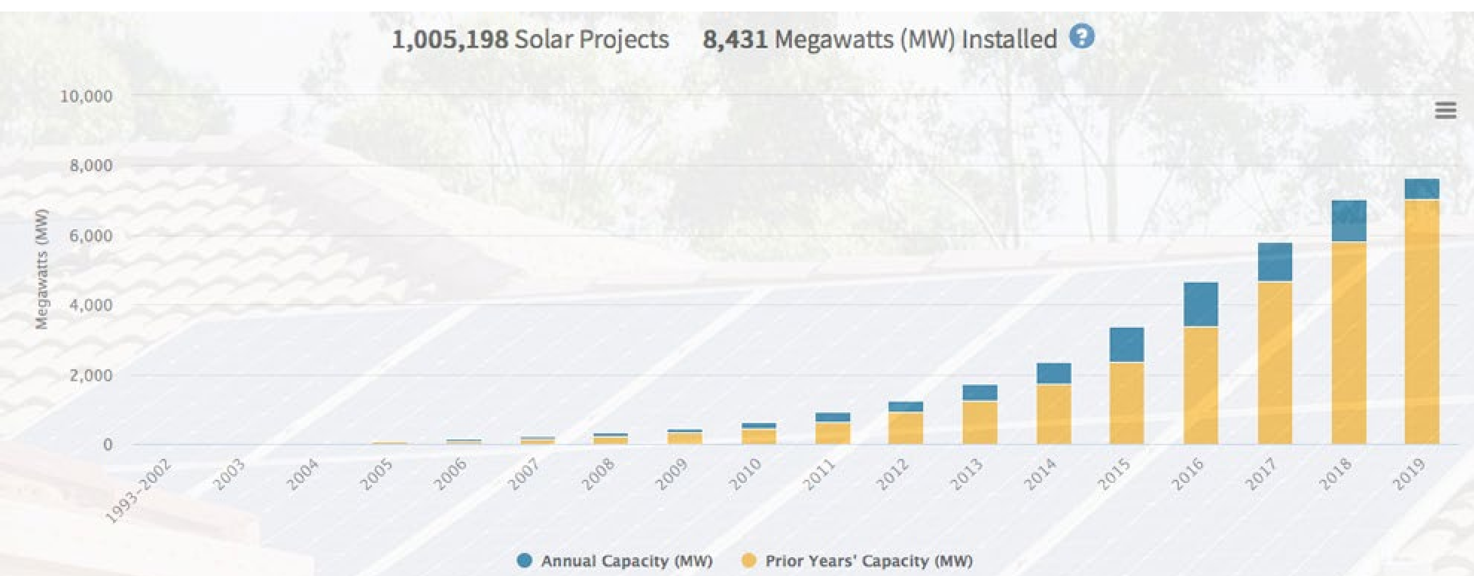
- All the grid operators said their interconnection processes are the same for DERs seeking to participate in wholesale markets regardless of whether they are interconnecting behind a retail customer meter. CAISO said that DERs, by definition, must have points of interconnection on the distribution grid. ISO-NE said DERs seeking to inject power into the system are subject to its Tariff if the interconnection is to an OATT distribution facility and to the state interconnection process if connected to a non-OATT distribution facility. NYISO said behind-the-meter resources that only reduce consumption and are not injecting power are not subject to the ISO's interconnection procedures.
- ISO-NE, NYISO, PJM and SPP said their interconnection process allowed studies for bidirectional service, although all but ISO-NE limited them to storage facilities. CAISO and MISO said they defer to the practices of the host distribution providers.
- None of the grid operators was able to provide definitive data in response to the commission's request for the number of DERs in each footprint that directly participate in wholesale markets versus the DERs that don't participate. All but PJM offered up some data, however:
  - CAISO referred to state *data* showing that California leads the nation in distributed generation. Its more than 1 million solar projects had a combined nameplate capacity of 8,431 MW as of July 31.
  - ISO-NE said DERs participating in its wholesale markets consist of 1,649 MW of "settlement only" resources (generation assets of less than 5 MW that are often connected to the distribution system) and 3,813 MW of demand resources (price-responsive demand, energy efficiency, load management, BTM generation and storage that reduce end-use demand). Although it said it lacked "visibility" on DERs outside its markets, it estimated there are 1,975 MW of solar PV generation not participating. It said it lacked similar estimates for combined heat and power facilities and batteries.
  - NYISO said it had 3,678 facilities providing 1,431 MW of demand response capability and one BTM net generation resource as of July 31, 2018. For non-ISO resources, it cited data from the New York State Energy Research and Development Authority estimating there are about 90,000 BTM solar PV installations in the state with a capability of 1,479 MW. NYSERDA also has estimated there are 300 to 400 non-solar distributed generation facilities, primarily combined heat and power facilities and energy storage, totaling 200 MW.
  - MISO said the resources participating in its markets include DR resources (28 resources with a combined target demand reduction of 672.6 MW), load-modifying resources (7,326.5 MW) and emergency DR resources (66 resources totaling 2,163.3 MW). It said it had no data on what share of those resources are connected on the distribution versus the transmission system. (It noted that its LMR data includes transmission-connected generators beyond the scope of FERC's queries.) MISO cited the Organization of MISO States' recent survey of utilities, which estimated almost 195,000 installations totaling 4,698 MW of DERs are not participating in the MISO market. (See *OMS: 4.5 GW of Unregistered DERs in MISO*.)
  - SPP said it has no DERs directly participating in its Integrated Marketplace, adding that it does not consider cogeneration facilities as DERs. It said it did not know how many DERs in its region are "part of the regulated retail environment."
- None of the RTOs was able to provide data on what share of the distribution facilities within their footprints were subject to a FERC-jurisdictional OATT. MISO, however, said it will begin tracking facilities that provide wholesale distribution service "in anticipation of DERs."
- All the grid operators said they were engaged with state or local authorities regarding the interconnection process for DERs or had done so in the past.

Below are individual summaries of the grid operators' responses.

CAISO's 'Great Lengths'

CAISO offered a robust *response* in keeping with its status as one of the most advanced incorporators of solar and other renewable resources.

"CAISO and its participating transmission owners have gone to great lengths to ensure that distributed energy resources can easily access



California leads the nation in distributed generation. | California Distributed Generation Statistics and participate in the CAISO's wholesale markets for energy and ancillary services," it said. "The CAISO Tariff allows distributed energy resources to access the wholesale markets quickly. The CAISO allows DERs to participate as standalone resources, aggregations and DR resources. The CAISO continually works to ensure that its Tariff keeps pace with emerging technologies and grid trends."

The ISO has been conducting a stakeholder process since 2015 on energy storage and DERs (ESDER), which has generated three sets of Tariff changes. It is now in its fourth phase of ESDER development.

In 2016, FERC approved what the ISO called its "first-of-its kind" process that allows DERs too small to meet the ISO's minimum capacity requirements — 100 kW for storage resources and 500 kW for conventional generators — to pool their resources and participate jointly in the CAISO market. The smaller resources can sell energy and ancillary services in CAISO as a distributed energy resource provider (DERP).

"Moreover, each CAISO transmission owner that is FERC jurisdictional and operates distribution facilities has a wholesale distribution access tariff (WDAT) with the express purpose of enabling DERs to interconnect to the distribution grid and still participate in the CAISO wholesale markets," the ISO said. "These transmission owners actively participate in CAISO stakeholder processes and update their WDATs to remain consistent with the CAISO Tariff."

A DER planning to participate in CAISO submits its interconnection request to its utility distribution company (UDC), with the applicable process set forth in the UDC's tariff, the ISO told FERC.

"The UDC performs all of the interconnection studies and administers the interconnection process, including the construction of network upgrades to mitigate any impact on the distribution or transmission grids. If the DER seeks a deliverability capacity allocation to be eligible to provide resource adequacy capacity, the CAISO performs the deliverability studies and informs the UDC of the results."

Before the DER goes live, it must complete CAISO's new resource implementation process to analyze the resource in the ISO's network model, register its scheduling coordinator and execute a participating generator agreement.

The process doesn't change if the DER is a QF or if it connects behind a retail customer meter, CAISO said. Whether participating individually or through an aggregation, all DERs interconnect to the distribution system under the applicable tariff of the UDC.

The California Public Utilities Commission's Rule 21 establishes the interconnection rules for state-jurisdictional utilities, requiring WDATs and DERs to mitigate any reliability impact on the CAISO grid.

CAISO said it doesn't keep data on the number or capacity of DERs in its market.

"DERs execute the same participating generator agreement that transmission-connected resources execute, and the CAISO's Master File and network models consider the voltage level of the point of interconnection, not whether that interconnection is considered transmission or distribution," the ISO said. "Determining whether each participating generator is interconnected to the transmission or distribution grid would require significant time and resources."

The ISO said "DERs' ability to participate in the CAISO markets has been a settled issue in California for many years. Recent regulatory coordination efforts have focused on modern, complex issues like [distributed energy resources aggregation], multiple-use applications and accounting for net energy metering resources.

"In addition, the CAISO continues to pursue discussion with transmission owners, UDCs and local regulatory authorities on managing the transmission-distribution interface with a high volume of DERs."

ISO-NE: DERs 19% and Growing

ISO-NE prefaced its *response* with a summary of DER participation in its markets, noting that its 7,437 MW of DERs account for about 19% of the region's total electrical capacity, most of it solar PV and energy efficiency. The RTO projects that by the end of 2028, installed PV nameplate capacity will exceed 6,700 MW and energy efficiency resources will reduce summer peak load by about 5,400 MW.

The RTO urged the commission to "afford regional flexibility" in any final order.

Schedule 23 of the ISO-NE OATT governs interconnections of small generating facilities (20 MW or less).

ISO-NE said it coordinates with the relevant TO regarding the status of the distribution facility in order to direct the DER developer to the applicable interconnection process. New or increased generation interconnections of 5 MW or greater require a "proposed plan application." Interconnections greater than 1 MW, but less than 5 MW, require a notification, unless the RTO determines the proposed plan will have a cumulative impact on facilities used for the provision of regional transmission service, in which case, an application is required.

The RTO requires an interconnection agreement for each POI, although each interconnection may include multiple units or devices. Two or more interconnection requests may be studied in a cluster if the conditions for clustering are triggered. Clustering is available when there is an interconnection queue backlog of two or more requests in the same part of the RTO's transmission system and none of the requests will be able to interconnect without significant transmission upgrades.

ISO-NE does not allow a single interconnection request for multiple generating facilities. However, it permits aggregation of multiple points of interconnection and multiple units behind a single POI for DR resources and alternative technology regulation resources.

The entity responsible for processing the interconnection request is determined by the status of the facility to which the DER generating facility plans to interconnect. Facilities that are part of the administered transmission system — existing pool transmission facilities (PTF), non-PTF and distribution facilities governed by the OATT — are subject to the RTO's interconnection procedures.

The interconnection studies assess the impact of the small generating facility's interconnection on both the transmission and distribution systems of the interconnecting TO.

Distributed Energy Resource (DER) Category	Settlement Only Resource (SOR) Nameplate Capacity (MW)	Demand Resource (DR) Maximum Capacity (MW)	Total DER Capacity (MW)
Energy Efficiency	-	2,822	2,822
Demand Response (excluding behind-the-meter DG capacity)*	-	214	214
Natural Gas Generation	22	246	269
Generation Using Other Fossil Fuels	63	354	416
Generation Using Purchased Steam	-	23	23
Non-Solar Renewable Generation (e.g., hydro, biomass, wind)	437	21	458
Solar PV Generation participating in the wholesale market	1,127	129	1,256
Electricity Storage	-	4	4
Solar PV Generation ***not*** participating in the wholesale market**	-	-	1,975
Total DER Capacity	1,649	3,813	7,437
Total DER Capacity/Total System Operable Capacity***	4.2%	9.8%	19.0%

New England distributed energy resources as of Sept. 1, 2019 | *ISO-NE*

MISO: DER Interconnections 'Untested'

MISO *told* FERC it doesn't keep track of resources at the distribution level and couldn't tell the commission the number or megawatt volume of DERs in its footprint.

The RTO said that, save for DR resources, it's not home to many DER installations and that it "does not anticipate significant penetration levels in the near future."

It said its existing interconnection rules only apply to DERs seeking to connect to distribution facilities that provide wholesale distribution service — which it deems as part of its transmission system for interconnection purposes. It noted that DERs must follow interconnection queue rules to participate in its capacity auctions.

"To date, however, MISO has not received nor processed a request from a DER to interconnect to such a facility. … The application of current rules to DERs remains untested in practice, and MISO's responses consequently are to some degree hypothetical," the RTO told FERC.

A connection to facilities that are not providing wholesale distribution service doesn't require a trip through MISO's interconnection queue. DERs would instead seek interconnection permission from distribution owners. In MISO, it's left to distribution owners to determine and alert MISO as to whether an interconnecting DER would impact the transmission system.

MISO also said it has yet to receive any requests to interconnect aggregated DERs, nor does it yet have rules in place as to how it would study aggregations for interconnection.

The RTO noted it's beginning work on a DER participation model with stakeholders and OMS and said its interconnection rules will likely require "carefully considered adjustments."

	Installations			Capacity (MW)		
DER Type	Residential	Non-Res	Total	Residential	Non-Res	Total
Solar PV	41,212	8,328	49,540	861	1,147	2,008
Wind	659	460	1,119	8	482	490
Electric Vehicle	4,101	-	4,101	0	-	0
Microturbine	-	4	4	-	9	9
Fuel Cell CHP	-	-	-	-	-	-
Fuel Cell Electric	-	-	-	-	-	-
Internal Combustion	1	385	386	0	634	634
Hydro	4	86	90	0	112	112
Gas Turbine	-	13	13	-	120	120
Battery Storage	37	9	46	246	3	250
Demand Response	137,210	1,796	139,006	118	131	249
Biodigesters	1	115	116	0	107	107
Other	14	31	45	0	718	718
Totals	183,239	11,227	194,466	1,234	3,464	4,698

DERs not currently participating in MISO markets | *Organization of MISO States*

"As MISO continues developing its DER aggregator participation model, MISO may reexamine the scope and applicability of MISO's interconnection process under various scenarios," the RTO added.

New Rules Pending for NYISO

NYISO prefaced its *response* by referring to its June 27 filing of proposed Tariff revisions to establish a new model allowing individual generating facilities located at the same bus to aggregate as a single resource to participate in the ISO markets (*ER19-2276*). (See *NYISO Management Committee Briefs: April 24, 2019*.)

Under the proposal, which is pending before FERC, an aggregation could consist of two or more generation, DR or DER resources with a maximum injection of 20 MW.

The proposal would expand the definition of "small generating facility" to include injections into the grid from generating units and energy storage of the same or different technologies located behind a single meter.

NYISO noted that DERs do not participate much in its markets currently except through DR programs that reduce the amount of energy that LSEs must obtain in the markets.

The ISO said it coordinates with TOs on a case-by-case basis to determine whether a proposed interconnection is to a distribution facility subject to the Tariff.

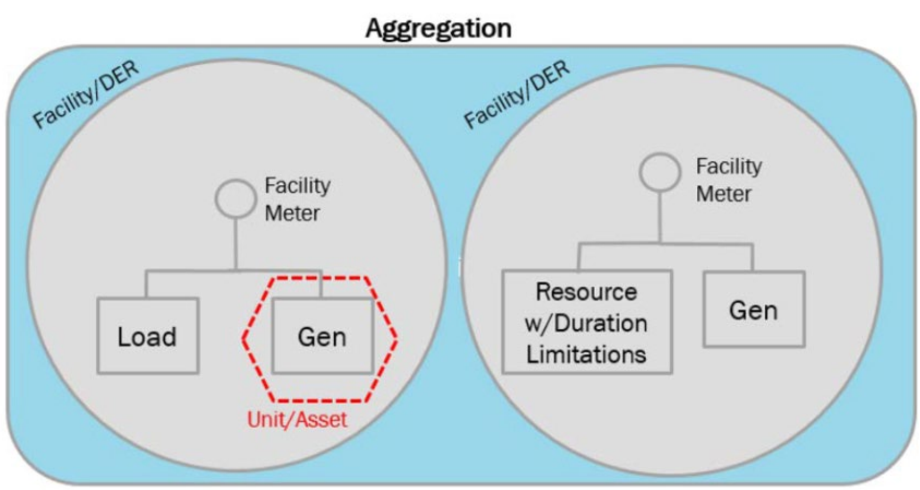
"The voltage of the facilities is not the sole criteria for making this determination," it said. "While generally facilities 45 kV and above are considered transmission, and facilities below 45 kV are considered distribution facilities, this is not always the case." How the TO operates its distribution system — whether radial or networked — is also important in this determination.

The proposed rules would also stipulate that generating facilities located at separate points of the grid may participate in an aggregation so long as all the facilities are electrically located at or downstream from the same transmission node.

The ISO said it will not perform additional studies based on an existing facility's determination to participate in an aggregation, regardless of whether they were subject to the small generator interconnection procedures (SGIP), standardized interconnection requirements (SIR) or utility interconnection procedures.

NYISO said it anticipates a substantial increase in the number of existing and new distribution-connected generating facilities that will seek to participate in its wholesale markets.

"Once such generating facilities begin to enter into service and start making wholesale sales, they will trigger the distribution facility to which they are interconnected as subject to the commission's interconnection jurisdiction going forward, which will increase the distribution facilities in New York subject to the commission's jurisdiction for interconnections for purposes of making wholesale sales," it said.



NYISO proposed expanding the definition of "small generating facility" to include net injections into the grid from generating units and energy storage. | *NYISO*

PJM: No Specific Aggregation Processes

PJM's Tariff does not outline specific aggregation processes, so each FERC-jurisdictional DER would require its own interconnection service agreement. Those outside the commission's authority require a wholesale market participation agreement. Tariff revisions would be required to accommodate aggregations of new and existing DERs at multiple points of interconnection, the RTO said.

The process for DERs interconnecting to both types is the same, PJM said, except that those seeking connection to non-jurisdictional facilities must execute any additional steps required by state regulators.

PJM said it has engaged in conversations with authorities in D.C. and several states — including Ohio, Pennsylvania and Michigan — regarding DER ride-through capability. The RTO produced a *report* comparing state interconnection procedures, including how they might apply to wholesale DER, with the help of state commissions. It also participated in Maryland's *PC-44* grid transformation proceeding, which "examined the applicability of Maryland jurisdiction to the interconnection of wholesale DER."

Bidirectional service studies are only conducted for energy storage devices capable of charging from the grid. PJM also does not consider BTM generation as eligible for wholesale participation.

The RTO doesn't keep track of how many DERs currently exist within the region, nor does it maintain data or estimates on which distribution facilities are subject to FERC jurisdiction versus those that are not.

DERs not Participants in SPP Markets

No DERs directly participate in SPP's market, the grid operator *said* in its filing. The RTO said it would consult with the interconnecting utility and the appropriate TO to determine whether an aggregate or individual affected-system study would be appropriate.

"The affected-system study is strictly for the purpose of determining impacts to the SPP transmission system," SPP said. It said it considers each interconnection point as a separate request, to be studied individually.

SPP said its Tariff allows individual DERs looking to join an aggregation to be studied under a cluster study, if the customer requests it.

"The DER's decision to participate in an aggregation would not trigger the RTO/ISO interconnection process," the grid operator said. "To the extent that the interconnecting utility determines that the aggregation would create the possibility that the DER could impact the SPP transmission system, the utility would have an obligation to inform SPP and to determine whether additional studies would be needed."

The grid operator said distribution utilities would be responsible for determining whether proposed DER facilities are under SPP's functional control and, if so, they would direct the customer to submit an interconnection request to the RTO. If the facilities are not under SPP control, the utility would determine whether there is a potential impact to the transmission system and notify SPP of the request. The RTO and interconnecting utility would jointly determine whether a study is necessary and which entity would conduct it.

If upgrades are required, SPP would tender an agreement to the customer for construction. The three-party construction agreement would be between SPP, the customer and the TO, which would own the upgrade. SPP would not be a party to any interconnection agreement.

Responding to FERC's question on how it defines the physical boundaries of a distribution facility when determining whether it is already subject to SPP's OATT for making wholesale sales, the RTO said its interconnection procedures only apply to facilities under its functional control.

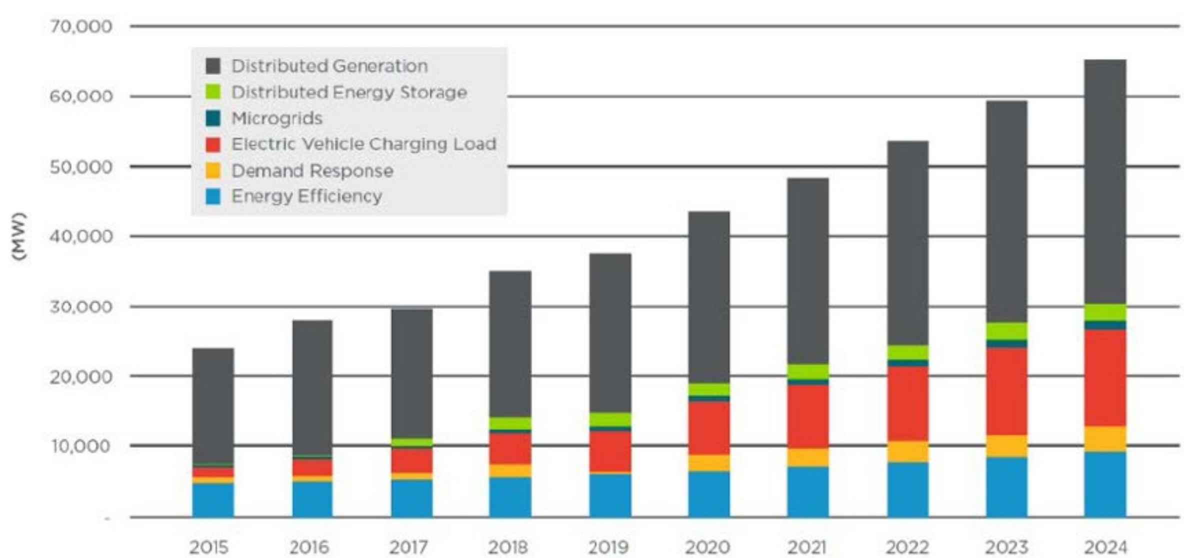
"Any resource, regardless of whether it interconnects to the SPP transmission system or not, may make wholesale sales … as long as it meets the other requirements under the Tariff for market registration and transmission service reservations, as applicable," it said.

The RTO said that whether energy storage resources are required to support charging activities would be determined by its interconnection study process, unless the customer indicates that it will not charge from the system.

If the facility is not an energy storage resource, the study process would only evaluate the effect of energy's injection into the system. If the facility includes network load, it may be subject to the Tariff's provisions for block-load additions, which is separate from the interconnection study process.

Asked how it would address individual DERs in an aggregation trying to interconnect to distribution facilities, some of which are subject to the Tariff, the RTO reiterated that only facilities under its functional control would be subject to its procedures. ■

Amanda Durish Cook, Rich Heidorn Jr., Tom Kleckner, Michael Kuser, Robert Mullin, Hudson Sangree and Christen Smith contributed to this report.



U.S. annual installed DER power capacity additions by DER technology, 2015-2024 | *Navigant Analysis*

Tx Developer Calls for Closer Look at NorthernGrid

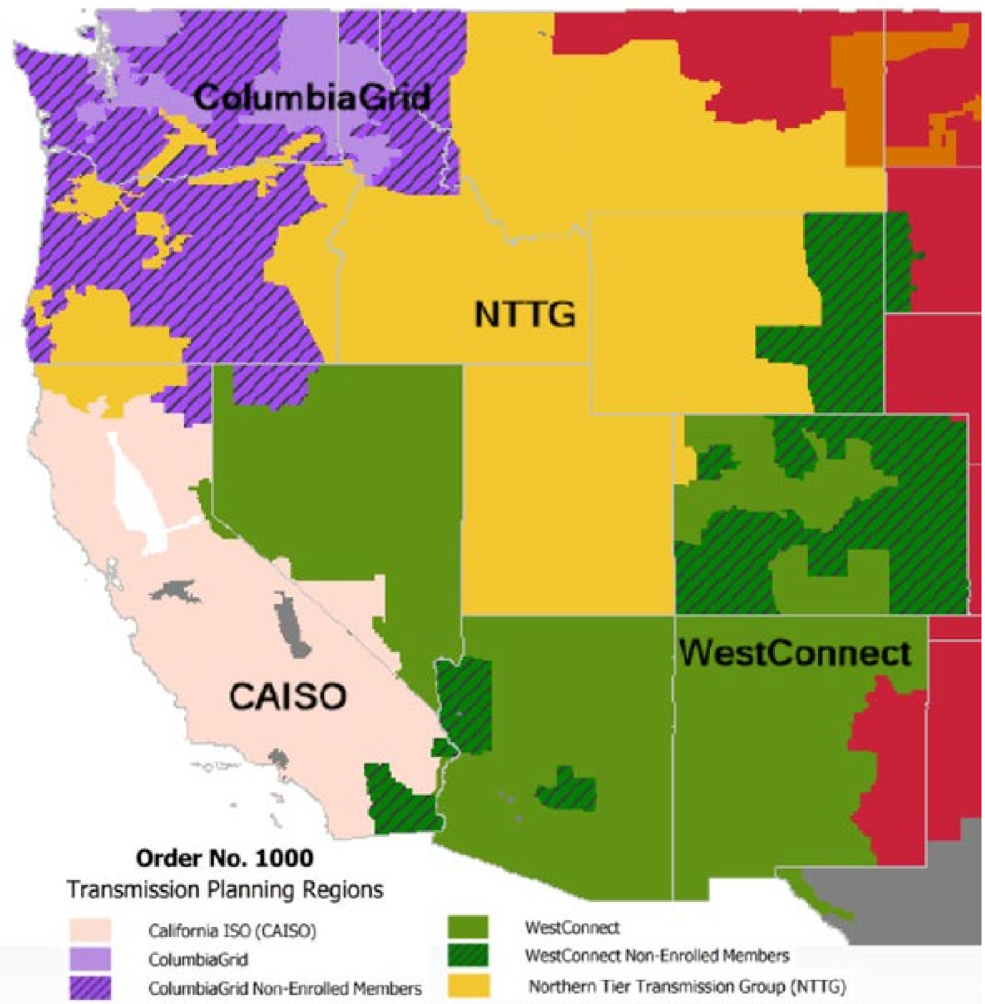
By Robert Mullin

A proposed merger of two Northwest transmission planning groups has won the endorsement of state regulators, but a prominent independent transmission developer is calling on FERC to convene a technical conference to scrutinize the effort before signing off.

In a limited protest submitted to FERC on Oct. 7, LS Power says it agrees in principle with the consolidation of ColumbiaGrid and Northern Tier Transmission Group (NTTG) into a single regional planning organization (RPO) called NorthernGrid (*ER19-2760*, et al.). But the company also questioned whether the new entity will be any more successful than its predecessors at producing the kind of regional transmission projects envisioned by the commission's Order 1000.

In that landmark 2011 order, FERC mandated that transmission providers participate in processes that produce a regional transmission plan and amend their tariffs to include procedures for public policy requirements. The order also sought to open projects identified in those regional plans to competition by nonincumbent transmission developers.

"To date, neither ColumbiaGrid nor NTTG have selected a single regional solution to transmission needs identified in the respective planning processes by individual transmission owners," LS Power wrote in its filing. "While LS Power is generally supportive of the endeavor to combine the two regions, it also believes that this is an opportunity to establish a transmission planning region that engages in meaningful regional planning that leads to the identification of more efficient and cost-effective transmission solutions rather than simply rolling up local transmission plans."



The new NorthernGrid regional planning organization would consolidate the areas currently covered by ColumbiaGrid and Northern Tier Transmission Group. | *ColumbiaGrid*

If approved by the commission, NorthernGrid's planning territory would encompass parts of California, Idaho, Oregon, Montana, Nevada, Washington, Wyoming and the entire state of Utah. Members would include ColumbiaGrid's Avista, Bonneville Power Administration, Chelan Public Utility District, Puget Sound Energy, Seattle City Light and Snohomish Public Utility District, along with NTTG's Deseret Power, Idaho Power, Enbridge, NorthWestern Energy, PacifiCorp, Portland General Electric and Utah Associated Municipal Power Systems.

In line with current practice, BPA and the publicly owned utilities — all non-jurisdictional to FERC — would be considered "non-enrolled" members in the new RPO. The RPO would coordinate their planning with their investor-owned neighbors, but they would not be subject to federal authority or Order 1000.

A Plan for Planning

The proposed merger is the result of a four-year effort to replace ColumbiaGrid and NTTG, the proponents noted in their Sept. 6 filings, which requested FERC approve the new RPO effective Jan. 1, 2020.

They said the merger will allow for "collaborative" regional planning on a single timeline, reduce member expenses through broader sharing of administrative expenses and reduce the interregional coordination requirements for all Western RPOs by eliminating one region. Membership would be open to any entity that owns or operates transmission facilities in the Western Interconnection, is electrically connected to an existing member or proposes to build a project making such a connection.

NorthernGrid would follow a two-year transmission planning cycle. The process would kick off with a gathering of input on study scope, including local transmission plans, new proposed projects (including Order 1000 candidates) and public policy requirements. Later during the first year, the RPO would develop the study scope and methodology and perform technical analysis and coordination with other regions. It would complete the year by issuing a draft regional plan.

Year 2 of the cycle would start with a review of the draft plan and an update of data points, followed by an update of the regional study scope and development of cost allocation solutions.

CAISO/West News

The process would wrap up later that year with a review of the final regional plan, allocation of cost responsibility for regional projects and plan approval.

'Fundamental Issues'

LS Power contends that NorthernGrid's planning process "raises fundamental issues about how the planning process should be structured," pointing out that the proposed process largely draws from existing processes used by ColumbiaGrid and NTTG — one the company said has been unsuccessful for independent developers.

"To properly evaluate whether the new NorthernGrid proposal will meet the commission's goals, the commission must look at whether the previously approved ColumbiaGrid and NTTG processes effectively met those goals," the company said. "Although those proposals were approved as compliant with Order No. 1000, the proponents now have at least five years of data available to test the effectiveness of the regional planning."

LS Power offered its own verdict: "To date, neither ColumbiaGrid nor NTTG have authorized a competitively determined transmission addition under their Order No. 1000 process."

The company also contends that "aspects of the proposal show that the planning process favors local transmission planning." It asked FERC to require NorthernGrid to engage in transmission planning that leads to the evaluation of projects that may be more efficient or cost-effective than local solutions.

LS Power said FERC should consider imposing additional requirements on NorthernGrid, including:

- giving developers and other stakeholders an opportunity to propose regional needs and solutions after NorthernGrid has finalized the study scope;
- clarifying when the region will determine whether a project proposed for regional cost allocation is a more efficient or cost-effective solution than a local project;
- revising the non-enrolled developer agreement to allow a developer to seek resolution at FERC through a complaint under Section 206 of the Federal Power Act;
- altering the governance structure to allow stakeholders to vote and ensure greater independence from incumbent transmission providers; and
- developing a pro forma agreement laying out the rights and obligations of a developer whose regional project is selected by the RPO.

LS Power also said the filing is deficient because NorthernGrid did not include a copy of its planning agreement with the non-enrolled members, such as BPA, whose transmission facilities "interconnect or are intertwined" with the systems of the RPO's "enrolled" members.

"The NorthernGrid filers intend to coordinate planning with non-enrolled nonpublic utility transmission providers. To that end, they developed a separate planning agreement that is substantially similar to the planning that occurs within Attachment K [of a transmission provider's tariff], but excludes the cost allocation provisions,'" LS Power said.

The company argues that FERC should hold a technical conference to evaluate how well ColumbiaGrid and NTTG have identified projects that solved their regions' needs "and, if those entities were not successful in identifying regional projects, whether that is due to flaws in the planning process that should be corrected so that the flaws will not carry over to the new (and combined) NorthernGrid."

"The commission should not accept the new Attachment K until these issues are better fleshed out. Commission precedent shows that a technical conference is good vehicle for fleshing out issues of this type," the company said.

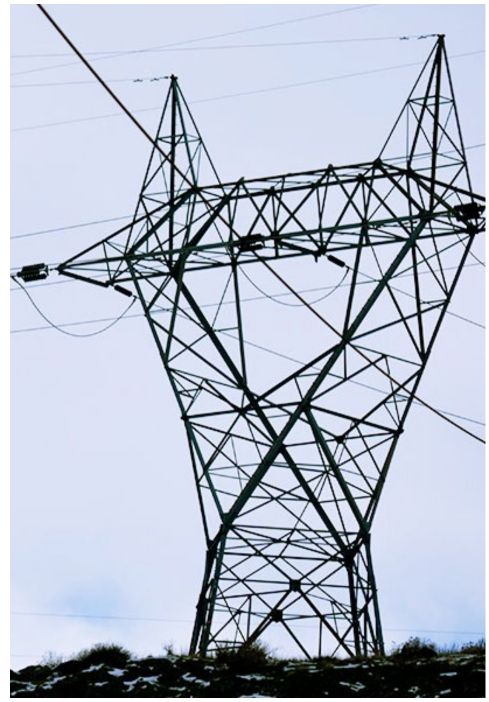
Proposal Addresses 'Key Concern' for States

The NorthernGrid proposal has earned the backing of a key constituency: state utility commissioners, who applauded the group for providing states with a "meaningful role" in planning through the appointment of two representatives from each state on an Enrolled Parties and States Committee.

"There, state entities and jurisdictional members may collaborate to form perspectives on the study scope and plan that the committee's co-chairs will carry forward to the NorthernGrid planning committee," commissioners from Idaho, Oregon, Washington and Wyoming wrote in joint *comments* filed with FERC.

The role of states in NorthernGrid had been a "key concern" for regulators because ColumbiaGrid had "no formal role for states distinct from other stakeholders," while utility regulators do have formal roles on NTTG's Steering Committee, they said.

The commissioners said they "appreciate the willingness of the NorthernGrid entities to



BPA line in The Dalles, Ore. | © *RTO Insider*

work toward a solution that recognizes the important role of states and accommodates many state priorities, even within a complex organizational structure." They pointed out that the footprints of the two planning regions already represent "an interconnected region with significant overlap" in customers, generation and transmission. Their combination "will better reflect the scope of the regional benefits of transmission solutions being evaluated, as well as produce administrative cost efficiencies that benefit customers across the region," they said.

They also contend that the "best regional solutions" will depend on investor-owned utilities collaborating with BPA and the region's publicly owned utilities.

"Navigating the legal and administrative complexity of an organizational structure that accommodates both Order 1000 entities and non-jurisdictional entities is difficult but necessary to achieve broad regional collaboration," they wrote.

The commissioners acknowledged that their concerns were centered on NorthernGrid's governance and that FERC must deal with many other organizational details in its review process. "Although we do not intend to take positions on any other issues that may arise, we do encourage FERC to evaluate the filing as expeditiously as possible, so that transition to the new organization can align efficiently with the beginning of the next two-year planning cycle," they concluded. ■

CAISO/West News

PG&E Restores Power amid Public Backlash

CEO Acknowledges Poor Performance

Continued from page 1

its effort to prevent the type of deadly and destructive fires that its equipment sparked during similar windy fall weather conditions in 2017/18. Those fires included the Camp Fire, which killed 86 people and destroyed much of the town of Paradise in November 2018.

At least one fire flared up last week near the San Francisco Bay Area community of Moraga but was quickly contained. No major wildfires occurred in Northern California during the blackout.

CPUC Responds

The PSPS was included in the wildfire mitigation plan PG&E filed with the California Public Utilities Commission earlier this year. The commission approved PG&E's plan in May. (See *California Regulators OK Utility Wildfire Plans*.)

CPUC President Marybel Batjer | *State of California*

That did not stop the CPUC from slamming PG&E at its voting meeting Thursday in San Francisco. In that meeting, new commission President Marybel Batjer said PG&E's actions were unsupportable. (See *Calif. Regulators Bash PG&E Power Shutoffs*.)

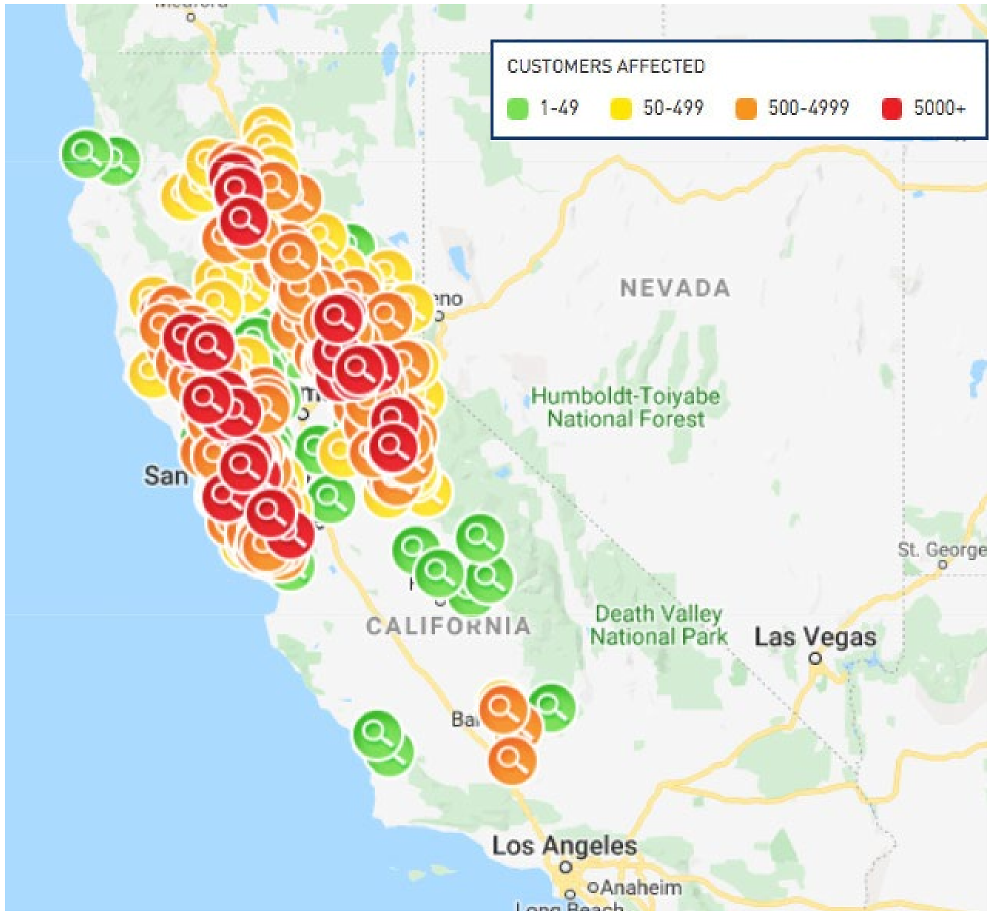
"The management and the response of the company, PG&E, to the [PSPS] have been absolutely unacceptable," Batjer said. "The impacts to individual communities, to individual people, to the commerce of our state, to the safety of our people has been less than exemplary.

"This cannot be the new normal," she said. "We can't accept it as the new normal, and we won't."

She called for a review of the public policies that led to by far the largest blackout to prevent wildfires ever to hit the state.

Commissioner Genevieve Shiroma suggested the massive shutoff wouldn't have been necessary if PG&E had maintained and upgraded its infrastructure to prevent fires.

"The sheer magnitude [of PG&E's PSPS] is indicative of the condition of the utility in terms of what we call the hardening — that means the condition of the poles, the lines, the wires, the transformers, the transmission lines — and the maintenance, or lack thereof, of the system and the vegetation management," Shiroma said.



PG&E said about 600,000 customers in northern and central California remained without power Oct. 10. | *PG&E*

The CPUC's deputy executive director for safety, Elizaveta Malashenko, told commission that the shutoffs affected about 2,400 miles of transmission lines and 24,000 miles of distribution lines. CAISO had been working to contain the shutoffs so that they didn't spill over into neighboring areas, she said.

The state had tried to help PG&E keep its website and servers working, soliciting help from the likes of Microsoft and other tech companies, she said.

Southern California Response

Several wildfires did occur in Southern California as hot dry Santa Ana winds blew late last week. The largest of the blazes was the Saddleridge Fire, which burned nearly 8,000 acres above the San Fernando Valley, forcing widespread evacuations.

Residents told several news outlets they'd seen flames beneath a Southern California Edison transmission tower Thursday night as the fire started, but those reports have yet to be confirmed by fire officials or SCE.

SCE had shut off power to thousands of its customers in the greater Los Angeles area to prevent fires, but a spokeswoman told the Los Angeles Times that the transmission line in question had not been de-energized.

All but four SCE customers had power as of Monday, the company said on its website.

Firefighters continued to make progress on the Saddleridge Fire, which was about 43% contained as of Monday morning, according to the California Department of Forestry and Fire Protection. Cal Fire said the blaze had caused at least one death. ■

CAISO/West News

Judge Admits PG&E Takeover Plan as Utility Blacks out Millions

Massive Fire Safety Shutdown Dwarfs Earlier Events

By Hudson Sangree

SACRAMENTO, Calif. — The federal judge overseeing PG&E's mammoth bankruptcy opened the door to a competing takeover plan Wednesday, potentially allowing a group of bondholders to seize control of California's largest utility from its current investor owners.

The move to end PG&E's exclusivity period — the time it has to offer its owner Chapter 11 plan unopposed — occurred as all eyes were fixed on PG&E's decision to shutoff power Wednesday to at least 513,000 Northern California customers in an effort to prevent the type of deadly fires that drove it to seek bankruptcy protection in January.

"[PG&E's reorganization] plan is on track as well as can be expected for now," U.S. Bankruptcy Court Judge Dennis Montali wrote in his *order* ending exclusivity. "That said, the parties most deserving of consideration [the fire victims], speaking through the [Official Committee of Tort Claimants], have changed their position from the last time the court considered terminating exclusivity, and spoken loudly and clearly that they want their and the Senior Noteholders' proposed plan to be considered.

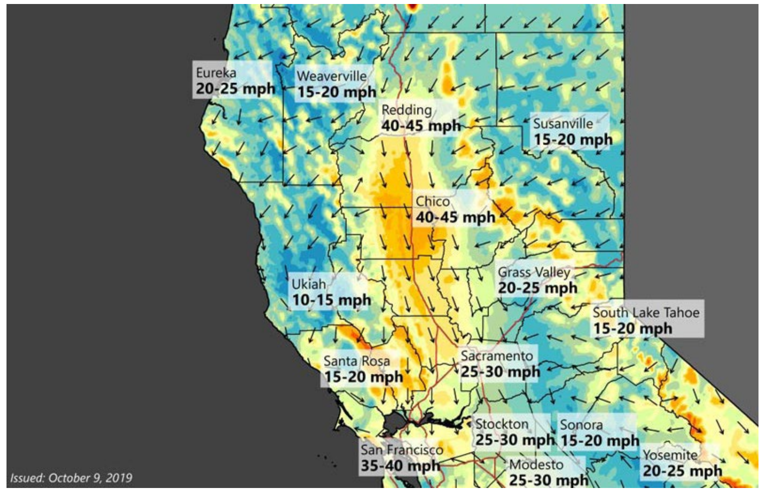
"The coming weeks will permit ample time to explore and resolve issues regarding both plans consistent with the more traditional plan vetting processes well-known by bankruptcy professionals," Montali wrote.

The judge instructed the bondholders to file their plan by this Thursday. In its preliminary form, the bondholders' plan proposed investing more than $29 billion in PG&E in exchange for a controlling interest in the utility. It includes a provision for paying wildfire claimants about $13.5 billion, insurance companies $11 billion and local governments $1 billion.

As Montali filed his order, PG&E had come under intense scrutiny for its decision to shut down power to large swaths of its service territory, citing gusty winds that could cause utility-sparked conflagrations like those of the past two fall fire seasons.

The unprecedented public safety power shutoffs (PSPS) — affecting as many as 800,000 customers and millions of residents in 34 counties — were by far the largest yet in a state struggling to protect its residents from fires that have turned dramatically more deadly and destructive in recent years.

PG&E faces billions of dollars in potential liabilities for the North Bay (or wine country) fires of early October 2017 and the Camp Fire of November 2018, which combined killed nearly 120 people and destroyed tens of thousands of homes. Those fires started in weather conditions similar to Wednesday's. (See related story, *Calif. Regulators Bash PG&E's Power Shutoffs*.)



High winds in Northern California prompted PG&E to intentionally black out much of its territory. | *National Weather Service*

"The safety of our customers and the communities we serve is our most important responsibility, which is why PG&E has decided to turn power off to customers during this widespread, severe wind event," Michael Lewis, vice president of PG&E electric operations, said in a *statement*. "We understand the effects this event will have on our customers and appreciate the public's patience as we do what is necessary to keep our communities safe and reduce the risk of wildfire."

The utility said its decision to turn off power was based on "forecasts of dry, hot and windy weather including potential fire risk."

Soon after midnight Wednesday, PG&E began its intentional blackout of approximately 513,000 customers in the Sierra Nevada foothills east of Sacramento, on the state's North Coast and in the mountainous landscape north of San Francisco. The first phase of its planned three-phase outage was completed about 4 a.m.

PG&E turned out the lights for 234,000 more customers in the San Francisco Bay Area and elsewhere later Wednesday, after postponing that move for at least several hours.

By Monday, the utility had restored power to nearly all of its territory.

Southern California Edison also *cut* power to about 13,700 customers in an area of northern Los Angeles County by Friday, with service restored over the weekend.

The winds that spread wildfires each fall in California are known as Santa Ana winds in the south and Diablo winds in the north. They fan blazes in vegetation dried out by the long rainless months of the state's Mediterranean climate.

Winds blew at 10 to 45 mph from the north and east in PG&E's territory, the National Weather Service reported Wednesday as it issued a red-flag warning. Gusts tend to blow hardest across Northern California's ridgetops, whipping wildfires into fast-moving firestorms that are nearly impossible for firefighters to control.

San Diego Gas & Electric began shutting down power proactively after a series of massive fires there last decade. SCE followed, as did PG&E starting last year. It considered shutting down power to the area scorched by the Camp Fire, which destroyed the town of Paradise and killed 86 people but opted not to. (See *Fire Season Starts in Calif. with Power Shutoffs*.)

Typical PSPS events have generally affected anywhere from a handful of customers to more than 5,000, according to *records* kept by the California Public Utilities Commission starting in 2013. PG&E upped the ante when it shut down power to 48,000 customers in late September, but last weeks' events dwarf that number.

CAISO said it did not expect "any impact to the bulk electric system for the duration of this event." ■

ERCOT News

Magness, Walker to Explain ERCOT Reliability to NERC

By Tom Kleckner

AUSTIN, Texas — ERCOT CEO Bill Magness and Texas Public Utility Commission Chairman DeAnn Walker will attend NERC's Board of Trustees meeting next month to address concerns over the grid operator's slender reserve margins, Magness told his Board of Directors last week.

"We invited ourselves," Magness told the board during its Oct. 8 meeting. "We were cordially invited but not asked to come."

NERC has raised issues over ERCOT's reserve margins before each of the last two summers. The grid operator has a 13.75% target planning reserve margin but has begun the last two summers with margins in the single digits. (See *Abundance of Summer Capacity — Except in Texas*.)

ERCOT's energy-only market has met record demand both summers, albeit while taking emergency actions twice in 2019.

"We've both talked to [NERC CEO] Jim Robb a fair amount recently about how we operate in the summer and about how ERCOT operates with the reserve margins we have," Magness said.

He said that NERC's summer outlook for ERCOT did not have reference reserve margins the organization uses as a standard, "and that raised concerns and lot of troubling thoughts at NERC and its board and what they had to communicate to [federal] regulators."

"Jim understands that we still get through it," Magness said. "This market is working very well to maintain reliability by using the market forces we rely on."

Magness said he and Walker will deliver a presentation on ERCOT's market scheme "and how we tend to make it work through very tough summers."

Intense August heat sent demand and prices soaring, forcing ERCOT to call two energy emergency alerts (EEAs), its first in five years. The grid operator recorded its two highest peaks during the month, at 74.7 GW and 74.6 GW. (See "ERCOT CEO Briefs Commission on Summer Performance," *Texas PUC Briefs: Aug. 29, 2019*.)

Continued high temperatures in September have provided one benefit to ERCOT: system administrative fees above forecast. Average system demand was up 7% during the month over 2018, with a new record of 68,959 MW.

PUC commissioners listen to staff 's input. | © *RTO Insider*

Magness *said* September's demand pushed ERCOT's positive variance in administrative fees from $4.6 million to more than $6 million. The grid operator's revenues were projected to be $26 million over budget through August. Expenditures are also expected to be over budget, but by $6.2 million through August.

Ironically, Austin saw temperatures dip into the lower 50s by the end of last week.

"It's much more comforting to talk about the summer when the weather's like this than when it's still summer," Magness told the board.

ERCOT MPs: Market Worked as Designed in Summer

ERCOT stakeholders on Friday praised the market's response to another summer of thin reserve margins and record-breaking demand.

Representatives of industrial consumers, cooperatives, public power, generators, marketers and retailers joined ERCOT staff and the Independent Market Monitor to offer their feedback on the energy-only market's results during a PUC workshop.

Attorney Katie Coleman, speaking for the Texas Industrial Energy Consumers trade group, recalled how "everyone would freak out" when projected reserve margins would fall below 12%. She credited the PUC and state government for sticking with the market's design.

"That has allowed ERCOT to do something that no other market in the world has done, which is to run a lean, efficient market with strong performance that saves the state money and encourages economic development," Coleman said.

Turning to other panelists, Coleman said, "We've all had our differences from time to time … but what we've built here is something everybody should be proud of."

Coleman said it was "remarkable" that the market survived a summer with "7, 8ish percent" reserve margins and only called two EEAs. She said the market was "able to get away with it, when nobody else in the world had," because of the $9,000/MWh price ceiling during scarcity conditions and because ERCOT's Capacity, Demand and Reserve (CDR) *reports* don't account for all available reserves.

"The threat of being exposed to a $9,000 price, either losing out on getting that $9,000 price or not being able to fulfill a forward commitment and having to buy power at a $9,000 price, incentivizes a really, really strong performance," Coleman said. "Secondly, the CDR does not count everything. … A 7 to 8% reserve margin is not a 7 to 8% reserve margin, primarily because it's not able to count the demand side accurately."

Coleman noted the CDR includes about 7,000 MW of emergency response service. However, if a generator is only awarded 30% of the

ERCOT News

ERS it has offered the market, she said, "those extra [megawatts] don't show up in the CDR. We know those are flexible, sophisticated loads, and when you have high prices, you'll get response from those loads."

Representatives for power generators and the retail electric providers (REPs) agreed the market worked as expected and designed during the summer months.

Fronting the Texas Competitive Power Advocates group, Michele Gregg said scarcity conditions during previous years of low prices were "not only expected, but also how an energy-only market is supposed to work and part of [its] success."

"The days this summer where we saw scarcity pricing, it was good to see that lining up with scarcity. We hope that is going to lead to good, firm capacity projects in the future," Gregg said. "Once sufficient generation is built, we expect prices will decline again. That's just how the market works. We haven't seen the sustained pricing … enough to build a combined cycle plant.

"We appreciate the regulatory certainty of allowing the rules to work," REP representative Cathy Webking said. "Customers in general benefited from that in the competitive market. The volatility in the scarcity market reflected scarcity, and while there were scarcity pricing mechanisms on the wholesale side, it's important to note customers on fixed-priced contracts for the summer saw none of that [volatility]."

ERCOT staff ***filed*** a presentation that reiterated much of what it has been saying for the past month. Senior Director of System Operations Dan Woodfin said the grid's tightest days came when wind energy fell off in the early afternoon, setting the stage for the EEAs and $9,000 prices.

However, on the system's record-peak day, renewable resources made above-normal contributions.

"It's an interesting phenomenon that we need to flesh out," Woodfin said. "I'm not sure if it's a meteorological phenomenon or as the wind [farms are] spread out over a larger geographical area, there's less chance of one storm to knock out the forecast."

Besides the two EEAs, ERCOT issued eight operating condition notices for reserve capacity shortages and 25 advisories when physical responsive capability dipped below 3,000 MW in August and September.

"Overall, the market outcomes supported reliability needs," Woodfin said.

As she has in several venues in recent weeks, IMM Director Beth Garza again stressed that high prices in ERCOT are no longer highly correlated with high temperatures, but when West Texas winds die down before the afternoon peak. (See "ERCOT Monitor: August 'High Excitement' for RT 'Geeks,'" ***FERC's Glick Navigates Political Dynamic***.)

"I'll say it one more time: High prices are increasingly correlated with high net load," she said, referring to load minus wind and solar generation's contributions.

Above-average temperatures in September have pushed ERCOT's real-time prices to their highest level since 2011, one of the hottest summers on record in the state. Garza said prices for the year are averaging $52/MWh through September, up from August's average of more than $50/MWh and 46% higher than last year.

Market representatives (left to right) Katie Coleman, Michele Gregg, Mark Dreyfus, Julia Harvey and Cathy Webking prepare to deliver their testimony. | *© RTO Insider*

Natural gas prices are still down 15% from last year, when real-time prices averaged $35.63/MWh.

September's heat resulted in an ERCOT peak demand record of 68,959 MW for the month. The grid operator broke the previous record for October by more than 2,300 MW on each of the month's first two days, reaching 64,670 MW and 65,066 MW.

PUC Assesses $647K in Penalties

During the morning's brief open meeting, the PUC handed out $647,500 in administrative penalties and $225,000 in bill-payment assistance funding.

The commission approved a settlement against Just Energy that docked the retailer $475,000 for not timely releasing "switch hold" for customers with past due bills. As part of the settlement, Just Energy agreed to contribute an additional $225,000 to bill-payment assistance programs (*49688*).

The PUC also approved a $23,500 penalty against the city of Garland's utility for failing to provide non-spinning reserve service (*49699*) and three settlement agreements against transmission and distribution utilities over annual service quality:

- Texas-New Mexico Power was fined $30,000 (*49618*);
- Southwestern Electric Power Co. was fined $45,000 (*49828*); and
- Southwestern Public Service was fined $74,000 (*49857*).

The commissioners signed off on CenterPoint Energy's request to adjust its energy efficiency cost-recovery factor, allowing the utility to recover $35.4 million in energy efficiency program incentives and administrative costs (*49583*).

Botkin Starts New Term as Commissioner

The open meeting marked Commissioner Shelly Botkin's first since she was ***reappointed*** to the PUC by Texas Gov. Greg Abbott.

Botkin's six-year term is set to expire in September 2025. She was originally appointed to the commission last year to fill former Commissioner Brandy Marty Marquez's term, which expired in September. (See ***ERCOT's Botkin Named to Texas PUC***.) ■

ERCOT News

ERCOT Board of Directors Briefs

Storage Task Force a Needed Response

ERCOT CEO Bill Magness told the board that a newly formed task force will improve ERCOT's response to the expected wave of battery energy storage resources.

ERCOT's Technical Advisory Committee created the *Battery Energy Storage Task Force* (BESTF) last month. (See "TAC Approves Task Force to Study Battery Energy Storage," *ERCOT Technical Advisory Comm. Briefs: Sept. 25, 2019*.)

The grid operator currently has 104 MW of installed storage capacity, adding 67 MW since 2016. Another 62 MW of storage is planned to be added in 2020.

"As big as the issue is getting and as many people are interested in coming in, we feel like we need to get a little ahead of it," he said. "There can be lots of different answers to some of these questions and challenges, but we just need some answers so we can incorporate them into the systems and models and enable participation of this new resource in the market. We feel like we need to further develop the rules and protocols around this issue."

ENGIE's Bob Helton, chair of the TAC, said the task force will benefit both the storage companies and the ERCOT market.

"They don't have the bandwidth to go to three, four or five stakeholder meetings to get what they need and to inject what we need," he said. "We need those people to tell us what they've seen and take advantage of their experience."

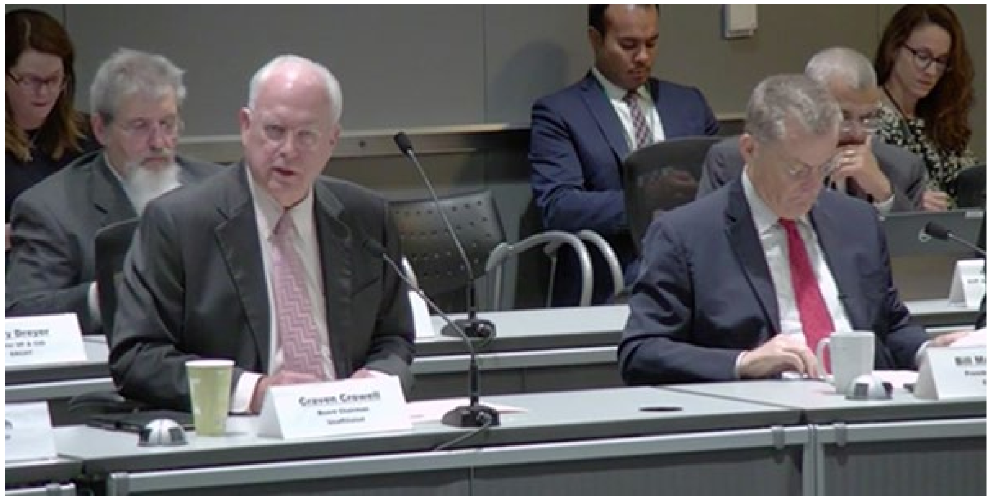
The team, which doesn't meet until Oct. 18, will be structured similarly to the Real-Time Co-optimization Task Force (RTCTF). It will be chaired by ERCOT's Sandip Sharma, with a members' representative to be selected during the first meeting.

The group will focus first on modifications to how energy storage is modeled and used on the system. Staff said the changes will make different storage configurations "more palatable" before a permanent fix is brought for approval by the end of 2020.

The BESTF's work will be timed to coincide with that of the co-optimization group, which is working on a three-year timeline. The task forces' design changes will be part of a major system upgrade in 2024.

Taylor, Spak OK'd as Vice Presidents

The board ratified the promotions of *Sean Taylor* to vice president and CFO and *Mara Spak* to vice president of human resources.



ERCOT Board of Directors Chair Craven Crowell (left), with CEO Bill Magness, opens the meeting Oct. 8.

Taylor, who has served as controller since joining ERCOT in 2013, replaces Mike Petterson, who announced his retirement after 18 years with the grid operator. Petterson will be honored during ERCOT's annual meeting in December, but not before participating in an ironman competition in Argentina.

Spak has four years with ERCOT and almost two decades of HR experience.

Board Approves Southern Cross Directive, 22 Changes

The board approved the latest directive for the Southern Cross Transmission DC tie-line, a proposed Pattern Development HVDC transmission project in East Texas that would ship more than 2 GW of energy between the Texas grid and Southeastern markets.

The directive requires ERCOT to develop and implement a methodology "to reliably and cost-effectively coordinate outages" once the DC tie is interconnected.

As part of its market oversight, the PUC approved the project but issued 14 directives to ERCOT, requiring that certain studies and determinations be made to accommodate Southern Cross. The project is expected to be energized in 2023 (*46304*).

The board unanimously approved 15 Nodal Protocol revision requests (NPRRs), two changes to the Nodal Operating Guide (NOGRR), a single revision to the Planning Guide (PGRR), two system-change requests (SCRs), a change to the Settlement Metering Operating Guide (SMOGRR) and a Verifiable Cost Manual update (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 to make resources whole after following ERCOT's instructions.
- *NPRR936*: Changes the congestion revenue rights auction transaction limit from that of the CRR account holder to the counterparty level.
- *NPRR939*: Replaces ERCOT's practice dividing load resources — other than controllable resources providing responsive reserve service (RRS) — into two groups. Those resources would instead be divided into small groups of 500 MW each to allow a smaller manual deployment of RRS to help them meet their ancillary service responsibility toward physical responsive capability.
- *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 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.
- *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 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 and better aligns the wind and solar capacity calculations used in ERCOT's Capacity, Demand and Reserves (CDR) report.
- *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-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 hourly publication of 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.
- *SCR803*: Adds to the wind-integration report a new graphical dashboard showing actual and forecasted solar production and creates new solar-integration reports.
- *SCR804*: Gives transmission operators access to ERCOT's GridGeo application, a browser-based tool that replaces the Macomber Map and gives better situational awareness of the ISO's transmission grid.
- *SMOGRR022*: Removes from the guide references to fiber-optic instrument transformers.
- *VCMRR023*: Aligns the manual's language with NPRR940's removal of gray-boxed language. ■

— Tom Kleckner

Magness explains the work in front of the energy storage task force.

ISO-NE News

Overheard at Renewable Energy Vermont 2019

Congressman Welch Predicts Extension of EV Tax Credits

BURLINGTON, Vt. — More than 300 people last week attended the annual Renewable Energy Vermont conference, where state officials, renewable energy advocates and a Vermont congressman described their efforts to combat climate change while calling for even more measures.

Here's some of what we heard.

Local, State and Federal


Olivia Campbell Andersen, REV | © *RTO Insider*

REV Executive Director Olivia Campbell Andersen asked state officials what action has had the most impact on their work to transition to a clean energy economy.

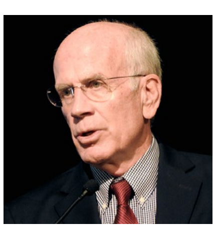
Vermont Department of Public Service Commissioner June Tierney highlighted the increase in media coverage of renewable energy, which has helped drive legislative engagement.


June Tierney, Vermont DPS | © *RTO Insider*

"Our legislature is really engaged now, which really makes a difference," Tierney said. "Kudos to Connecticut and New York for leading. ... I'm not so concerned about being in the vanguard, but of bringing people along.

"We have been leaders in Vermont. ... When we adopted a renewable energy standard in 2015, it was the finest in its time," she said. "But the most impactful thing has been the regulator's mind, and the degree to which the regulator has been open to these changes."

She said more is demanded of regulators in a small state like Vermont, where the legislature has invested the responsibilities for planning, envisioning and economic regulation in the DPS.


Rep. Peter Welch (D-Vt.) | © *RTO Insider*

Rep. Peter Welch (D-Vt.) said, "Tax credits make a huge difference at the beginning of a technology," adding


Vermont DPS Commissioner June Tierney speaks to the 2019 REV conference on Oct. 10 in Burlington. | © *RTO Insider*

that the House of Representatives "may be able to do something on the electric vehicle front by extending the tax credit."

Welch is a member of the bipartisan Advanced Energy Storage Caucus in Congress and co-sponsor of the Energy Storage Tax Incentive and Deployment Act (*H.R. 2096*), which would establish an investment tax credit for energy storage.

The caucus is focused on integrating renewables into the grid, increasing electrification of heating and transportation, and improving energy efficiency, he said.

"Whether the existing investment [EV] tax credits we have now will be extended or not, we don't know yet, but my experience has been that there is hugely bipartisan support to extend," Welch said. "The question is always when and how that's going to get done, and it usually gets done at the very end of the session, when there's an overall omnibus budget bill and tax agreement. ... My prediction is they will be extended."


Vermont Lt. Gov. David Zuckerman | © *RTO Insider*

Vermont Lt. Gov. David Zuckerman said, "The Trump tax cuts supposedly offered about $500 million to Vermonters in savings in their federal taxes, but over $300 million is going to the top 10% of Vermonters. My guess is that most of that $300 million is probably not going to be spent in Vermont; it's going to be sent to Wall Street."

Zuckerman proposed instead to take half that money from wealthy residents and spend it on

ISO-NE News

in-state programs such as weatherizing houses or expanding broadband access in rural areas.

"We do not have time for slow, incremental change," Zuckerman said.

Burlington Mayor Miro Weinberger | © *RTO Insider*

Burlington Mayor Miro Weinberger proposed imposing a statewide carbon pollution fee in Vermont to help cut carbon dioxide emissions 37% by 2040, calling it "perhaps the most critical thing we can do to address the climate emergency, and that would create a transformative tailwind that pushes into all of our other efforts to decrease carbon emissions."

Weinberger said the carbon charge would not be a tax, but a "revenue-neutral carbon fee," as "money collected by the state would be rebated back to Vermont households and businesses and keep those resources working in the economy."

Regional Reflections

Peter Olmsted, NYSERDA | © *RTO Insider*

Peter Olmsted, chief of staff at the New York Energy Research and Development Authority, said his state started its clean energy revolution a decade ago as it sought "to understand how the utility business model was going to evolve and respond to the needs of consumers, the need to respond to climate."

"We do not have time for slow, incremental change."

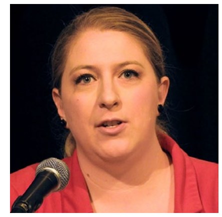
– Vermont Lt. Gov. David Zuckerman

However, understanding the necessary changes to regulators' thinking has been "the bigger challenge for us, whether it be a matter of prioritization of issues, capacity and resources, [or] an asymmetry of information between the regulator and the regulated," Olmsted said.

Regarding reliability, Olmsted said that "80% of our transmission lines were put in service before 1980, and over the next 10 years, the investment to upgrade those is going to be on the order of $30 billion."

New York needs to reconcile aging infrastructure with plans to develop "a significant amount of renewable energy and clean energy resources on the grid simultaneously... so energy storage we believe is a key ingredient in that," he said.

The interconnection "queue for NYISO has just exploded," Olmsted said. "We were at 200 MW in the queue in 2018 when we commenced our energy storage roadmap process, and we're now seeing upwards of 5,500 MW in our queue, so we know the demand and the interest is there."



Marissa Gillett, Connecticut PURA | © *RTO Insider*

Connecticut Public Utilities Regulatory Authority Chair Marissa Gillett said her agency had just a week earlier initiated a *proceeding* on grid modernization. (See *Overheard at the 163rd NE Electricity Roundtable*.)

"We're trying to enable an economy-wide decarbonization, which mirrors the executive order seeking 100% zero carbon by 2040," Gillett said. "We're also working to make a resilient, reliable and secure electricity commodity supporting growth in the green economy."

The cornerstone of the state's grid modernization proceeding is affordability, not only for residential customers, but also for commercial and industrial ones, she said.

RMI View

Jules Kortenhorst, RMI | © *RTO Insider*

Jules Kortenhorst, CEO of the Rocky Mountain Institute, said, "We were a think tank, but the time for thinking is over. We are facing a climate crisis and the clock is ticking.

"The accelerating pace of an energy transition may become the wind in our sails, just when we need it most," he said in comparing two contrasting views of the transition, one that thinks it best to go slow and the other that says the planet is on an exponential curve for warming.

Kortenhorst finds hope in the seemingly most mundane area of efficiency: "boring old building codes."

"If we don't get our buildings to near net-zero emissions, there is no way we're going to reach our climate goals," he said.

He also highlighted that solar is in many places of the world already the most cost-effective way to produce electricity, and 90% of natural gas projects in the country are now beaten economically by wind and solar.

"And it's a global trend ... in the buildup to the Paris [Agreement on climate change], India said it would build half coal and half solar. ... Now they see the economic benefit of leapfrogging," he said.

"As we are starting to deploy batteries to stabilize our electricity grid and to make solar

Left to right: Olivia Campbell Andersen, REV; Marissa Gillett, Connecticut PURA; Peter Olmsted, NYSERDA; and June Tierney, Vermont DPS. | © *RTO Insider*

ISO-NE News

available at the end of the afternoon when the sun is setting, we are driving down the cost such that electric cars become cheaper, at which point Ford, GM and Chrysler see that the future is electric, which drives costs down even further, which makes it easier to store the solar energy in batteries for our grid," Kortenhorst said.

"These feedback loops are starting to build on themselves, and we see a dramatic shift in the way in which people are starting to understand that if we weave a complex of web of renewable energy solutions, we will be able to shift to a low-carbon energy future much faster and much more cost-effectively."

Diverse Experience

Vermont imports four times as much energy as it produces within the state, and the largest utility, Green Mountain Power, "is highly dependent on imports from [Canadian] hydropower and nuclear power from Millstone and Seabrook, [which] are long distances away, as is most of the hydropower," said Kim Hayden, who leads the energy and environment practice group at the Burlington-based law firm of Paul Frank + Collins.

Kim Hayden, Paul Frank + Collins | © *RTO Insider*

"Seabrook and Millstone are among the two most vulnerable nuclear units in the country subject to inundation, based on [studies that took] a lot of time and effort by the Nuclear Regulatory Commission after Fukushima," Hayden said. She noted that one study resulted in NRC adopting a rule (*84 FR 39684*) requiring owners of coastal plants

"These feedback loops are starting to build on themselves, and we see a dramatic shift in the way in which people are starting to understand that if we weave a complex of web of renewable energy solutions, we will be able to shift to a low-carbon energy future much faster and much more cost-effectively."

- Jules Kortenhorst, CEO of the Rocky Mountain Institute

to modify their infrastructure "to withstand the levels that are now expected from storm surges and severe inundation."

Hayden called for better planning, such as fixing the transmission constraints associated with the Sheffield-Highgate Export Interface (SHEI), which prevents the development of new renewable energy resources in northern Vermont. She also said the state should increase its renewable energy standard.

Rebecca Towne, CEO of the Vermont Electric Cooperative, agreed with Hayden's concerns about long-distance imports, saying that utilities would ideally like to pair load and generation in the same location — and hopefully synchronize the periods of demand and output.

Rebecca Towne, Vermont Electric Cooperative | © *RTO Insider*

"Vermont is not a very big state, and so it doesn't take a very far transmission line to get out of state ... and anything that goes by transmission line, by nature, whether it's in-state or out-of-state, is not paired generation and load," Towne said.

"So the SHEI challenge is too much renewable generation in the northern part of Vermont, versus the load," she said. "The problem we run into is the location and timing of all that generation and the load is mismatched. The real way to fix that is to go with more transmission lines, but that doesn't really make any sense, mostly because our load is going down."

Chris McKay, WEG Electric | © *RTO Insider*

Storage has the unique characteristic of being either load or generation, depending on when it's needed, said Chris McKay, director of sales for battery energy storage solutions at WEG Electric in Barre, Vt.

"That ultimate dial or control is something you can do with a battery that the utilities and other planners are trying to create through other means, with controllable loads and dispatchable generation," McKay said. ■

— Michael Kuser

MISO News

MISO Files Offer Cap Revisions Ahead of Schedule

By Amanda Durish Cook

CARMEL, Ind. — MISO is hoping to avoid the need for a sixth straight waiver of its $1,000/MWh offer cap this winter, filing a year ahead of a FERC deadline to double its hard cap.

The RTO on Oct. 1 filed for the third time a proposal to adopt a $1,000/MWh soft cap and a $2,000/MWh hard cap on energy offers — and make corresponding changes to its demand curves (*ER20-11*).

MISO had until Oct. 1, 2020, to implement a $2,000/MWh hard cap for verified cost-based incremental energy offers after FERC last year said its plan still needed a few tweaks. While the commission accepted much of MISO's plan to permanently double its hard offer cap, it also required the RTO to pledge to apply the new hard cap to adjusted energy offers from fast-start resources. (See *FERC OKs MISO's Doubled Offer Cap, Orders Alterations*.) The new filing is considered a "true-up" filing rather than a compliance filing, the RTO said.

MISO plans to go live with the new offer cap by Dec. 1, having completed "two or three back-and-forths with FERC," Senior Market Engineer Chuck Hansen said at Thursday's Market Subcommittee meeting.

Executive Director of Market Operations Shawn McFarlane said he hoped the filing would supplant the need to request a sixth waiver of its $1,000/MWh offer cap this winter. (See *MISO Gets 5th Winter Waiver of Offer Cap*.)

Hansen said MISO was able finish its offer cap work ahead of deadline because it and market platform vendor General Electric found themselves with more time while they await a FERC order on the RTO's plan to incorporate energy storage resources into its markets. MISO originally asked for an order on energy storage compliance by July 1 while anticipating "significant" software work thereafter on a storage participation model.

Hansen also said additional staff time was freed up because FERC has yet to issue a final rule for RTOs to craft a participation model for distributed energy resources.

Hansen said MISO will only seek a sixth waiver if FERC rejects the filing. That waiver would closely resemble the last five it filed, he said, with verified energy costs above $1,000/MWh recovered via revenue sufficiency guarantee payments.

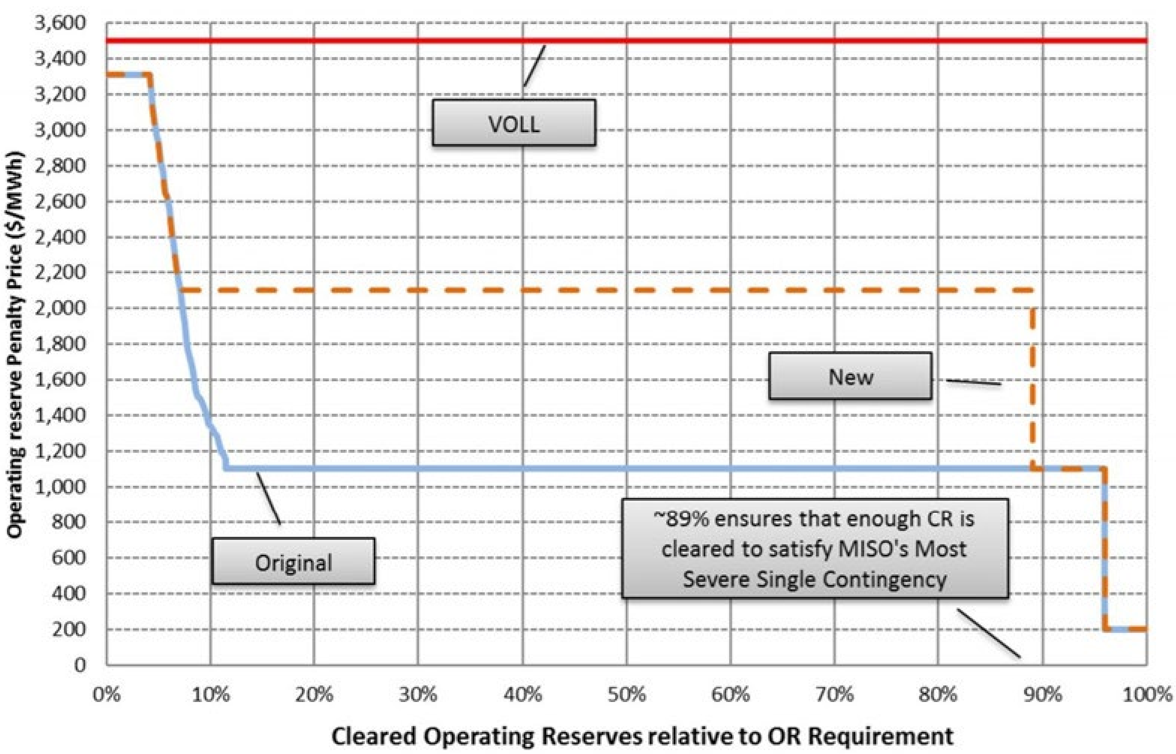
MISO's offer cap plan specifies that all resources, regardless of type, are eligible to submit cost-based energy offers above $1,000/MWh. This time, it added that fast-start resources will not be able to set prices above the $1,000/MWh soft cap or above the $2,000/MWh hard cap without offers first being verified or mitigated by the Independent Market Monitor.

Along with the higher caps, MISO has added a $2,100/MWh prolonged step to its operating reserve demand curve (ORDC) so that resources will receive nearly double the energy price when supply is scarce.

The ORDC will begin at $3,300/MWh, dropping to $2,100/MWh for much of the curve when the RTO clears 8% of its requirement level. At 89%, the level falls to MISO's original $1,100, remaining there until 96% or more of the requirement is cleared, when the curve flattens at $200.

MISO is planning to maintain its $3,500/MWh cap on the value of lost load (VoLL) over the Monitor's longstanding criticism that VoLL could be pushed as high as $12,000/MWh to create a more sloped contingency reserve demand curve.

Hansen said MISO still plans to work with stakeholders in the coming months to recast VoLL limits. ■



New MISO ORDC | *MISO*

MISO News

MISO Market Subcommittee Briefs

Restoration Energy Pricing in the Works

CARMEL, Ind. — MISO is planning a spring filing with FERC to implement a payment structure for resources that re-energize islanded areas of the grid following a blackout.

"It's interesting to stand up here and talk about something that we hope never happens. But we do see value in having a process," Director of Settlements Laura Rauch told stakeholders at Thursday's meeting of the Market Subcommittee.

MISO's preliminary *proposal* stipulates that, as a starting point for pricing, compensation for restoration energy will rely on resources' last submitted offers before an emergency strikes, resulting in unique costs based on each resource rather than a uniform clearing price. The RTO will allow for recovery of start-up costs, emergency purchases and resource-specific energy costs. It will also include recovery for any unusual costs incurred during operation, provided they can be verified by the Independent Market Monitor. The RTO will also accept after-the-fact updates of offers.

Restoration pricing differs from MISO's existing black start services definition because black start resources derive their revenues from the capacity they provide, not the energy market.

Rauch said restoration events will be considered over when the day-ahead market once again takes over economic dispatch of resources in the islanded area.

"We'll need to define the area of impact and the island," she added.

Rauch said MISO realizes load and generation totals during a restoration event "may be imbalanced" but said total generation costs will be allocated on a load-ratio share. The RTO had originally considered allocating resource costs based on local balancing authority boundaries, but this summer it said load ratio would be simpler to implement.

RTO officials have also said a fixed-price compensation approach for restoration energy would be a blunt instrument that would at times result in under- or over-collection by generators.

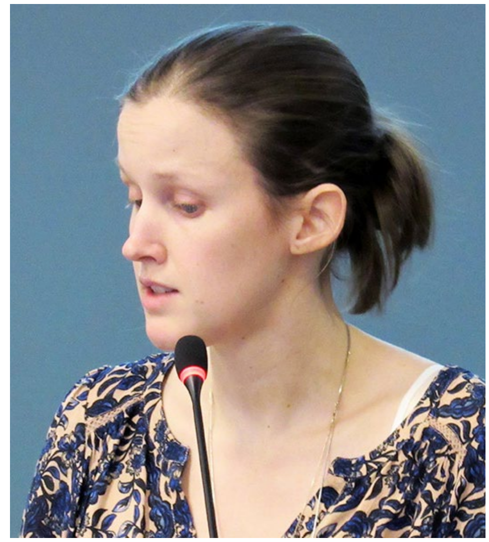
"The downside is that it's much more complex," MISO Director of Market Services John Weissenborn said in June of a unit-by-unit pricing calculation and settlement based on offers.

MISO Preps Tariff for Short-term Reserves

Although MISO filed with FERC on Oct. 4 to include a short-term reserve product definition in its Tariff (*ER20-42*), stakeholders shouldn't expect generators to fire up to furnish the reserves until late 2021.

The RTO asked that the commission act on its request by Jan. 31 but make the revisions effective Dec. 7, 2021, seeking a waiver of FERC's 120-day maximum notice requirement to give its Monitor and stakeholders "adequate time to budget for in advance and develop and test significant software and other operational adjustments."

MISO said it's already begun working with tentative market platform replacement vendor General Electric on software design details.



Laura Rauch, MISO | © *RTO Insider*

The reserves are meant to supply energy within 30 minutes to meet reliability needs and reduce make-whole payments, and MISO expects them to be especially useful in portions of MISO South, where the RTO's subregional transmission limit restricts imports.

MISO expects the short-term reserves product to clear $4 million in revenue annually when it goes live in 2021. It also estimates an approximate $5 million annual net production benefit when the reserves are used. Part of the savings will result from RTO operators taking fewer out-of-market actions, for which it must make revenue sufficiency guarantee payments. (See "Short-term Reserves," *Stakeholders Confused over MISO Roadmap*.) ■

— Amanda Durish Cook

MISO News

MISO RASC Briefs

MISO Pushes Back Deliverability Requirements

CARMEL, Ind. — MISO says it will wait another year before moving to tighten deliverability requirements in its capacity auctions, a decision that has irked stakeholders who say guaranteed deliverability to load is too essential to put on hold.

MISO's Independent Market Monitor has argued that the RTO doesn't properly account for capacity deliverability because its loss-of-load expectation (LOLE) study assumes that all capacity resources are fully deliverable on an installed capacity (ICAP) basis. However, MISO allows resources to demonstrate deliverability only up to the unforced capacity levels, which tend to be about 5 to 10% below full ICAP levels.

The Monitor has said MISO should require deliverability for all capacity resources based on full ICAP, after finding that one unit came up short by "tens of megawatts" in the 2016 Planning Resource Auction.

The RTO has so far developed possible solutions only for intermittent resources, citing the increasing number of wind curtailments in the footprint. It noted that curtailments *rose* to an all-time high of nearly 5 GW in May — although multiple stakeholders said it is missing key context on when such curtailments occur, arguing that curtailment at peak demand is very different from curtailment at 3 a.m.

At a Resource Adequacy Subcommittee meeting Wednesday, MISO adviser Darrin Landstrom said the RTO plans to estimate the average capacity factor for intermittent resources based on their transmission service request values, which will possibly reduce capacity credits.

The solution is one of three options MISO shopped in August to address the issue. (See *MISO Deliverability Plan Prompts Skepticism*.)

But that solution wouldn't apply to the capacity auction until the 2021/22 planning year, staff said. Landstrom said MISO would likely be unable to make a filing before the end of the year.

"I really don't think it's acceptable that MISO will delay a solution another calendar year," Gabel Associates' Travis Stewart said, urging staff to come up with a temporary solution in time for the 2020/21 planning year.

MISO has *acknowledged* that the Monitor might dispute capacity auction rights if the deliverability gap causes a "significant" change in clearing prices.

IMM staffer Michael Chiasson said MISO does not need to make a FERC filing to apply stricter deliverability requirements for conventional generation; it need only change its Business Practices Manuals.

But RASC liaison Patrick Brown said capacity resources need time to react to the change. He also said the RTO needs a year to make complex software changes to accommodate new deliverability requirements.

Complaint over Extended Outage Rule Change

MISO is sticking with a less aggressive plan designed to dissuade capacity resources from taking long outages that could risk supply and plans to submit a FERC filing later this month.

The provisional change would limit extended planned outages to a cumulative 90 days of the first 120 days of the planning year — June 1 to Sept. 30 — which MISO deems the most critical months in terms of demand. Resources that are unavailable for more than 90 days during the first four months of the planning year would be disqualified from auction participation. (See *MISO Eases New Rules on Extended Outages*.)

Tim Bachus, MISO's capacity market administration analyst, said the temporary change is only meant for the 2020/21 planning year auction. He said he's heard criticism that the proposal is too lenient, with some stakeholders asking instead for a 30-day outage limit.

Darrin Landstrom, MISO | © *RTO Insider*

"This is really a short-term fix ... one, maybe two years total," Bachus said. "We just want to address resources that take capacity payments but aren't available at the most critical times."

The short-term proposal might tackle Wolverine Power Supply Cooperative's late September complaint with FERC over MISO allowing a yearlong planned outage of a large resource in Michigan in the 2019/20 auction (*EL19-102*). The RTO currently issues no penalties for capacity resources that take extended outages.

The co-op said MISO's Tariff flaw "was exposed most recently by the results of the 2019/2020 PRA that created a capacity shortfall in Michigan's Lower Peninsula; yielded objectively unjust and unreasonable clearing prices well below the prices that would motivate new investment or keep older existing units in operation; and ensured that market participants were inadequately compensated for their actual capacity contributions." Wolverine argued it's not fair to consumers and market participants that MISO allows resources to set clearing prices even when their owners are aware they will be unavailable for the planning year, undercutting market principles and jeopardizing reliability.

New PRA Deadlines Approved

In a brief letter order Oct. 3, FERC gave MISO permission to shift its deadlines for its capacity auctions, allowing market participants more time to prepare data submittals and end the RTO's practice of opening and closing the offer window in the middle of the night (*ER19-2559*).

Under the rule changes, demand response testing, submission of generator verification testing data, behind-the-meter registration, unforced capacity values and the posting of preliminary auction data will be due at different points in the winter instead of fall. MISO will also open its four-day offer window at 8 a.m. ET and close at 6 p.m. instead of the usual midnight-to-midnight run. (See "New PRA Deadlines Before FERC," *MISO Resource Adequacy Subcomm. Briefs: Sept. 12, 2019*.)

The new deadlines will take effect beginning with the 2020/21 PRA. Some planning resource performance data, including generation verification test capacity, is due Oct. 31. Load-serving entities must submit their peak demand forecasts for the upcoming planning year by Nov. 1, the same date that MISO will publish the results of its annual LOLE study. ■

— Amanda Durish Cook

NYISO News

NY Court Rejects Challenge to ZEC Program

By Michael Kuser

A New York court last week rejected a challenge to the state's zero-emission credit program, dismissing a suit by Hudson River Sloop Clearwater and others against the Public Service Commission's 2016 decision to establish the program to subsidize economically unviable nuclear plants.

Acting Justice Roger D. McDonough of the New York Supreme Court in Albany County dismissed all of the suit's main complaints in a decision that could still be appealed to the state's highest court, the Court of Appeals.

In their suit, the petitioners argued that the PSC had already authorized the retirement of the R.E. Ginna nuclear plant before implementing the ZEC program and that it failed to properly assess the potential impact of the James A. FitzPatrick plant retiring. They also complained that the PSC's Tier 3 category for existing renewables under the Clean Energy Standard (CES) was arbitrary and capricious and that it failed to follow its own ratemaking guidelines for monopolies in developing the program.

"There was adequate administrative support for PSC's adoption and implementation of Tier 3 ... [and] the PSC has offered a rational basis for their ZEC pricing methodology in the unique circumstances presented herein," McDonough wrote in his ruling.

James A. FitzPatrick Nuclear Power Plant in Scriba, N.Y. | *Entergy*

He also refused to award any costs, fees, disbursements or attorneys' fees to the petitioners.

Part of the legal challenge concerned the commission's decision to use the federal government's social cost of carbon metric to determine how much to pay nuclear power plants for the value of their avoided carbon emissions.

"This ruling affirms that the social cost of carbon is an appropriate and effective tool for state policymakers," Richard Revesz, director of the Institute for Policy Integrity at NYU School of Law, said in a statement. "New York was right to use the [SCC] in valuing the environmental benefits of avoided carbon emissions. The court ruling could help provide guidance for other states pursuing climate policies."

The institute had filed an ***amicus brief*** arguing that the commission used the SCC exactly as intended, to internalize the external cost of carbon emissions.

Federal Court Backing

The 2nd U.S. Circuit Court of Appeals last September upheld the ZEC program, rejecting the argument that it intrudes on FERC jurisdiction (*17-2654-cv*). In upholding a district court's dismissal of the complaint by the Electric Power Supply Association and others, the appellate court said its finding was "consistent" with the 7th Circuit's ruling upholding Illinois' own ZEC program. (See ***Appeals Court Upholds NY Nuclear Subsidies***.)

The PSC created the program in August 2016 as part of the CES, which set a goal of reducing greenhouse gas emissions by 40% by 2030.

The commission said the program avoided the issues behind the U.S. Supreme Court's April 2016 ruling in *Hughes v. Talen*, which voided Maryland regulators' contract with a natural gas plant as an intrusion into federal jurisdiction over wholesale power markets.

In a briefing to the court, the Coalition for Competitive Electricity, Dynegy, Eastern Generation, NRG Energy, Roseton Generating and Selkirk Cogen Partners — independent power producers that compete with the nuclear plants — and co-plaintiff EPSA claimed the ZEC program "is not an environmental measure ... [but] merely a mechanism to benefit the owners of the nuclear power plants." ■

PJM News

PJM to Pay $12.5M to Settle GreenHat Dispute

By Christen Smith

PJM will pay two trading firms $12.5 million to end a dispute over the 890 million MWh GreenHat Energy default under a settlement agreement filed with FERC on Thursday.

Apogee Energy Trading and Boston Energy Trading and Marketing (BETM) will accept credits of $5 million and $7.5 million, respectively, to resolve the firms' claims of economic harm that resulted from PJM's decision to not liquidate GreenHat's entire portfolio of financial transmission rights during the 2018/19 planning period (*ER18-2068*). After the company defaulted in June 2018, PJM reran only the July FTR auction — a decision the RTO says kept costs to members down and avoided a cascade of market violations that would increase uncertainty for years to come.

"Those payments are integral to an overall package that allows payors in PJM to avoid the risk of the additional default allocation assessments that might result if the proceeding were litigated to conclusion," the RTO's attorneys wrote in the settlement. "PJM and many settling parties also attach considerable value to the settlement's removal of a cloud over the July auction and subsequent FTR auctions in the same planning period, and in avoiding the possibility of disruption to such auction results."

Apogee and BETM had opposed PJM's request to waive existing rules to settle the remainder of GreenHat's portfolio. PJM sought the waiver to reduce the impact on the monthly FTR auctions throughout the rest of the year. After FERC denied the request, the firms protested the RTO's subsequent motions for rehearing and clarification.

In June, FERC gave PJM stakeholders 90 days to settle all disputes before kicking off a paper hearing on the clarification request. (See *FERC: PJM Settle Disputes Before GreenHat Hearing*.) On Sept. 9, PJM confirmed a settlement in principle had been reached but declined to give further details. (See *GreenHat Energy Settlement Outlined to MIC*.)

Throughout discussions, PJM and the two firms disagreed over how much economic harm the original auction results caused. In the agreement filed Thursday, the RTO said the payments serve as a proxy for rerunning the July auction.

"When sophisticated parties reach such a settlement, the resulting compromise value can be expected to reflect the parties' efforts to protect their respective interests, based on their separate assessments of adverse litigation outcomes, the cost of litigation, impacts on market viability and the value of preserving settled market outcomes,"

PJM wrote. "Such is the case here. Rather than engage in complex and extended litigation about each method, practice and assumption that might be used to rerun or resettle the July auction, Apogee, BETM and the payor settling parties explored whether they could reach agreement on payment levels, informed by the differing estimates of economic harm by PJM and Apogee, and by PJM and BETM."

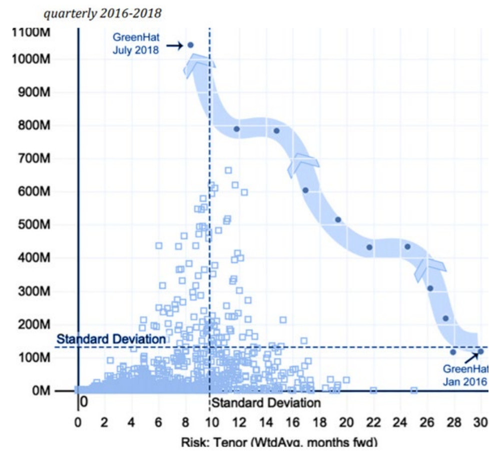
In addition to Apogee and BETM, the settling parties were American Electric Power Service Corp., American Municipal Power, Buckeye Power, DC Energy, Direct Energy Business, Direct Energy Business Marketing, Dominion Energy Services, Duke Energy Kentucky, Duke Energy Ohio, East Kentucky Power Cooperative, EDF Trading North America, EDF Energy Services, EDP Renewables North America, Elliott Bay Energy Trading, Exelon, FirstEnergy Service Co., LS Power Associates, Mercuria Energy America, Mercuria SJAK Trading, NextEra Energy Marketing, NRG Power Marketing, the PJM Industrial Customer Coalition, the PSEG Companies and Southern Maryland Electric Cooperative.

Although PJM did not describe the settlement as uncontested, it said "none of the settling parties shall seek rehearing of an order approving or accepting this settlement without modification or condition." The other settlers aren't asking for money because they believe they benefited from the way PJM ran the July 2018 auction and settled the remainder of GreenHat's portfolio.

PJM members are funding the credits to Apogee and BETM through default allocation assessments. PJM said it will establish another $5 million fund for additional claimants, though it anticipates there won't be any, based on the limited protest filings it received during the proceeding.

After receiving their credits, Apogee and BETM will be subjected to the same default allocation assessments that other members face. PJM spokesperson Jeff Shields told *RTO Insider* on Monday the default will cost members $177.5 million — substantially less than the cost of rerunning the July auction.

"The settlement is the product of intensive good faith negotiations among the participants to this proceeding," he said. "It brings to a close open issues around the treatment of defaulted



Size and tenor of GreenHat's portfolio | *PJM*

GreenHat portfolio. The settlement is supported by a broad array of stakeholders, there has been no indication that it is opposed by anyone, and it is in the public interest."

PJM said it will rerun the July auction for the sole purpose of supporting the credit payments established in the settlement. The simulation will liquidate the entirety of GreenHat's portfolio, which would impact FTR auctions in any month between September 2018 and May 2019. If any of the FTRs offered for liquidation would set price, then the simulated auction is rerun after removing 50% of the total defaulted FTR positions, regardless of path or period. PJM would waive all applicable Tariff rules concerning simultaneous feasibility test violations; prohibitions on selling FTRs not owned by an auction participant; FTR forfeitures; and requirements for participants to post additional credit based on tentative clearing results.

"The agreement not to apply the Tariff rules listed above is a key benefit of the 'black box' approach to settling this case," the RTO's attorneys wrote. "If PJM actually reran the auction, the referenced rules could cause cascading deviations from actual settlement results in other auctions conducted for the 2018/19 planning period, likely creating additional Tariff violations, further disrupting the market and undermining market participants' faith in the finality of the FTR auctions."

PJM asked FERC to waive both the reply comment period and the regulations necessary to effectuate the settlement. The RTO and the settling parties will answer questions on the deal in a meeting at FERC from 1 to 3 p.m. Oct. 17. The meeting will be available via teleconference (Phone: 800-375-2612; Meeting Access ID: 379441). ■

Court Waives Ohio Preregistration Law

By Christen Smith

Perry nuclear power plant | *FirstEnergy*

A federal court temporarily waived Ohio's preregistration law for petition circulators last week after a group collecting signatures for a statewide ballot referendum against nuclear subsidies claimed its opponents were stalling their efforts through harassment and bribery.

Ohioans Against Corporate Bailouts filed a lawsuit in the U.S. District Court for Southern Ohio that accused supporters of the state's nuclear subsidies of offering bribes to undermine its attempt to collect 266,000 signatures by an Oct. 21 deadline.

The organization asked the court to immediately suspend a state law that requires it to disclose the identities of its petition circulators to the secretary of state on a "Statement of Receiving or Providing Compensation for Circulating a Statewide Issue Petition," called *Form 15*. Failure to file the form is a fifth-degree felony under Ohio law, however, the group said the mandate violates free speech rights.

The group alleges that its opponents accessed the referendum circulators' identities through public records requests and used it to target them, offering cash bribes to abandon the campaign or buy their signatures. The *suit*, filed Oct. 7, also asked for another 90 days to collect signatures.

At a hearing on Friday, Judge Edmund Sargas Jr. suspended the Form 15 requirement through Oct. 25, saying that without injunction, "the plaintiffs will suffer irreparable harm."

"The interests of the public would be best protected by the enforcement of plaintiffs' First Amendment rights, and any third-party injury could be minimized by statutory mechanisms for detecting and deterring election fraud," Sargas said.

Advanced Micro Targeting, a Nevada-based company that manages the referendum effort, said in a declaration filed Wednesday that its employees spend up to eight hours processing Form 15s for each new hire. Some 15 to 20 potential employees have been lost because of the "time and burden" involved with the process, and the company says it will not take on future statewide referendum efforts "in light of significant diversion of time, energy and resources" necessary to comply with state law.

The "draconian" Form 15 mandate, one-month delay in getting the petition approved and interference from "well-funded and overly aggressive" opposition has further complicated the referendum effort, the group said in court documents.

"This administrative requirement only serves to make our petition circulators targets," Chris Finney, an attorney for the organization, said in a press release. "One of our circulators was called less than hour after they filed their Form 15 with the state of Ohio and received an offer to quit working for the campaign if they would take a buyout bribe."

Sargas rejected the organizations' two other requests — to waive state laws that require government approval of petition summaries and certain signature distributions across counties — but did not explain why.

If the referendum is approved, voters would decide whether to overturn House Bill 6, which would provide $150 million annually to First Energy Solutions' two nuclear plants starting in 2021. The suit names as defendants Ohio Secretary of State Frank LaRose, who is responsible for certifying or rejecting the ballot measure. Also named was Columbus City Attorney Zach Klein, who is responsible for enforcing violations of the Form 15 requirements in the state capital.

The group's suit does not identify those who took part in the alleged bribery attempts. The referendum drive is being opposed by groups calling themselves Ohioans for Energy Security and Generation Now.

FES did not respond to requests for comment on the allegations Wednesday. Attempts to obtain comments from Ohioans for Energy Security and Generation Now also were unsuccessful.

However, Carlo LoParo, a spokesman for Ohioans for Energy Security, *told* Cleveland.com the lawsuit was a "desperate act."

"It's now clear why they've peddled irresponsible rumors and made unsubstantiated charges over the past few weeks. They can't get Ohioans to sign their jobs-killing petition," he said.

State Attorney General Dave Yost said in a *letter* to the U.S. attorneys in Columbus and Cleveland that media reports of harassment and intimidation concerned him and that he intended to use all of his office's resources to "protect the integrity of the petition process."

Petition "supporters have a right under law to collect signatures without interference," he *said* in a press release. "My job as attorney general is to call balls and strikes like I see them, and this one is a wild pitch. It's time to knock it off."

The federal suit is the latest twist in the organization's sprint to gather nearly 266,000 signatures over three months to get the referendum on the November 2020 ballot. (See *Ohio Nuke Ballot Petition Approved*.)

FES asked the state Supreme Court to block the vote last month, arguing that the new ratepayer fees — ranging from 80 cents up to $2,400/month — are equal to a tax, making the legislation ineligible for being overturned by voters. (See *FirstEnergy Solutions Challenges Nuke Vote in Ohio Supreme Court*.)

LaRose, in an *answer* filed with the Supreme Court last month, denied the company's assertion that he had any legal duty to stop the petition. ■

PJM News

Report: PJM's Summer Operations 'Uneventful'

By Christen Smith

PJM's grid coasted through an "uneventful" summer highlighted by a new record for weekend peak load and the lowest forced outrage rate in five years — the result of evolving resources and system planning, the RTO said in a *report* published Wednesday.

"The system would not have handled these high demands as smoothly a decade ago," said Kevin Hatch, a supervisor in PJM's dispatch system operations. "We are seeing generators that are increasingly responsive to our operational requests, a transmission system that is more robust, and the benefits of efficient and reliable resources through the capacity market."

Summer demand peaked at 151,558 MW on July 19 in the midst of a hot weather alert — one of 13 called in the region during the season, which spanned June 1 through Sept. 15. The following day, the grid set a new weekend peak load record of 149,751 MW. The average LMP hovered around $25/MWh, with prices during the daily peak spiking to $45/MWh.

Although "relatively" mild weather enhanced the grid's smooth performance, the report emphasizes the "excellent coordination and cooperation" of PJM members, including responsiveness to dispatch operations, system upgrades and the influx of more efficient generators via the capacity market. These newer resources have replaced aging equipment, driving forced outage rates below 3% this summer, the RTO said.

"We appreciate the cooperation and coordination with our member utility companies," said Mike Bryson, PJM's senior vice president of operations. "More efficient generators mean fewer outages, greater reliability and a more efficient system overall."

The report also credited lower fuel prices — combined with the season's hottest temperatures occurring during periods of lower demand — for keeping LMPs down. Average daily gas and coal prices were 64 cents/MMBtu and 31 cents/MMBtu cheaper, respectively, compared to 2018.

No capacity emergency procedures occurred during the summer. PJM reported three spinning events and 13 hot weather alerts, the fewest recorded in a summer season since 2014. The grid experienced less than 80 post-contingency local load relief warnings, another five-year record low.

Two "notable" gas pipeline events caused temporary disturbances in PJM, according to the report. On Aug. 1, a 30-inch segment of the interstate Texas Eastern Transmission Pipeline in central Kentucky exploded, just a few miles south of a gas-fired generator that serves PJM. The explosion did not harm the unit, and operators isolated the damaged section, saving the grid's supply of shale gas that flows through the region.

Six weeks later, a compressor station in Northern Virginia on the Dominion Energy Transmission pipeline failed during scheduled maintenance. PJM said a "spell of later summer heat" and the typical generator outage season meant that certain units downstream of the station lost gas supply temporarily. No emergency procedures were issued.

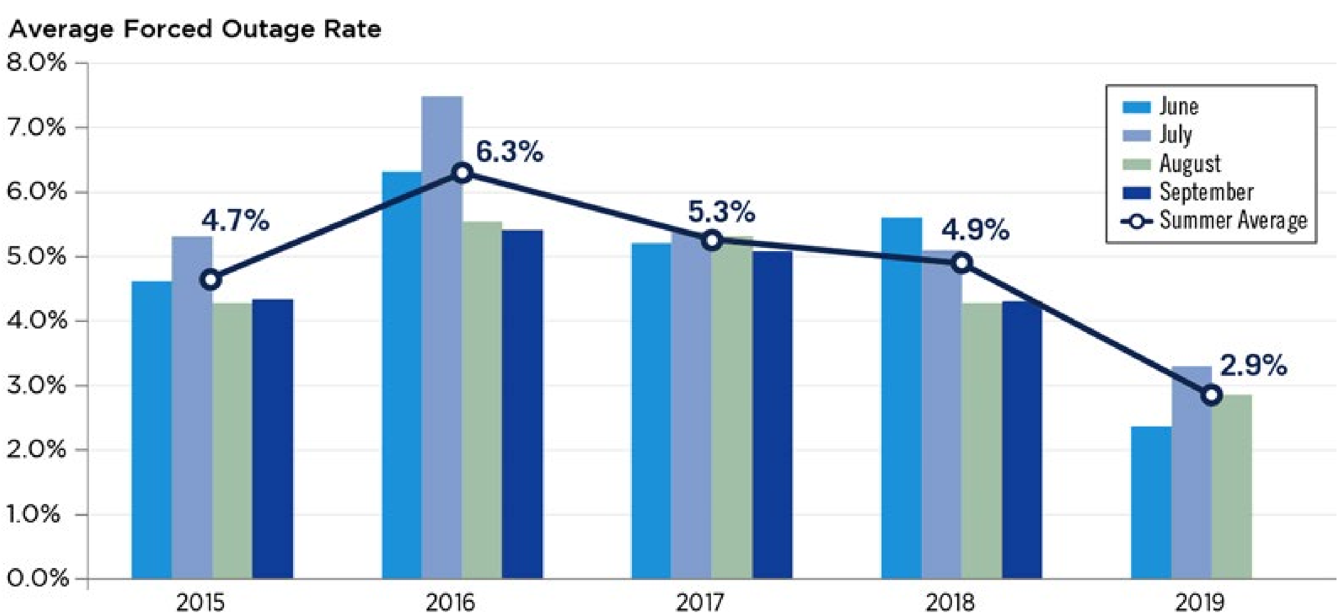
Shoulder Season Surprise

An unexpected hot weather alert on Oct. 2 forced PJM to call upon demand response resources to effectively manage the 126,000 MW peak load.

The RTO declared a pre-emergency load management reduction action just before noon in the American Electric Power, Baltimore Gas and Electric, Dominion and Pepco zones. This directive triggered a performance assessment interval — which measures the production of all resources with Capacity Performance commitments in the affected zones — that lasted approximately two hours.

"We count on our utility partners, generation resources and load management to perform during these tough days, and they did just that," Rebecca Carroll, PJM's director of dispatch, said in a *statement* Oct. 2.

Although the event occurred outside the summer season, PJM will address both the report and the DR event at its Operating Committee meeting today. ■



Average forced outage rate | *PJM*

PJM News

Lake Erie Connector Capacity for Sale

By Christen Smith

ITC Holdings said last week it's looking for utilities to buy capacity on the *Lake Erie Connector*, an underwater 345-kV HVDC transmission line that will transmit 1,000 MW of power back and forth between Ontario and Pennsylvania.

The "shovel ready" project has cleared the last of its permits, ITC Chief Operating Officer Jon Jipping told *RTO Insider* on Friday, and the company now hopes the five-year investment of time and money spent jumping through regulatory hurdles in the U.S. and Canada will pay off.

"We had a really big plan and gave ourselves enough time," he said of ITC's progress since acquiring the project in 2014. "The connection of these two markets is going to bring some real savings."

Lake Erie Power Corp. first conceived of the project in 2013 as a solution to the Ontario Independent Electricity System Operator's excess power and congested transmission lines and PJM's growing demand for emissions-free generation. (See *Merchant Transco Plans 1,000 MW Line into PJM*.)

Jipping said Ontario's renewables penetration could help PJM states meet their clean energy targets, while Pennsylvania's vast reserves of shale gas could provide lower-cost energy to the Canadian province.

"We took a strategic and tactical view of the project to go and get the permits, spend the money and get the land rights because we really felt it lent a lot more credibility to what is a very unique project," he said. "It's two countries, it's connecting new markets, going across a big lake."

The project mirrors other underwater transmission lines in France and Spain, Jipping said, and carries lower risk thanks to the progression of HVDC technology. Still, he said the construction — which will take upward of three years — isn't without challenges.

"I don't want to say it's easy, but it's fairly straightforward," he said. "Lake Erie is not very deep. It's much less challenging, technologically, compared to the offshore wind projects in New Jersey." (See *Orsted Wins Record Offshore Wind Bid in NJ*.)

PJM's most recent generation interconnection facility *study* estimates network upgrades for the project will cost $4.7 million with an in-service date of March 31, 2024. The 73-mile bidirectional line will traverse underneath Lake Erie to connect a retired 4,000-MW coal plant in Nanticoke, Ontario, to a new converter station in Erie, Pa., which will eventually tie into Penelec's existing Erie West substation. Neither the RTO nor the utility had anything to say about the project at this phase.

RTO Insider reached out to Erie County Executive Kathy Dahlkemper to discuss her dealings with ITC throughout the permitting process. Although she was unavailable for comment, Dahlkemper told Buffalo's NPR affiliate in 2017 that she didn't expect the project to cause problems in the community where ITC planned to build the new convertor station.

"You have to understand that this is coming into Erie County in probably one of the least populated areas, particularly along the lake," she told *WBFO*. "So the impact to where people live to their property is actually fairly minimal because of where they are coming in to our county."

The Lake Erie Connector Project will use HVDC technology to transmit 1,000 MW of power between Ontario and Pennsylvania. | *ITC Holdings*

Jipping told *RTO Insider* on Friday that early concerns from Erie residents about property values and water contamination were allayed through public meetings and slight changes to the developer's initial construction plans. He said company representatives will return to the local townships once construction begins to answer more questions.

"We were able to explain what we were doing and were able pick routes that were minimally impacting the community," he said. "We had to buy a little more property than we wanted and do some route changes, but that's pretty normal for us." ■

SPP Seams Steering Committee Briefs

SPP, MISO Ponder Tx Projects to Eliminate Settlement Agreement

SPP staff told the Seams Steering Committee on Wednesday that MISO is pursuing a number of transmission projects to help it escape from under a settlement agreement that governs the connection between its two regions.

MISO said in July that it is evaluating nine projects to supplement or substitute for the contract path that links its Midwest and South regions over SPP's system. (See *MISO Studying Projects to Cut North-South Tx Reliance*.)

"MISO wants to get rid of the settlement agreement — specifically, the $27 million in transmission payments they're making," Casey Cathey, SPP's manager of reliability planning and seams, told the committee during its monthly meeting. "They have a stack of projects they've looked at. … They're being very transparent."

Cathey said MISO intends to fold the projects into its planning efforts, which will be completed by the end of 2020. Similarly, he said, SPP would like to incorporate MISO's work into its own planning processes and into the RTOs' next coordinated system plan.

"This is an opportunity for us to have a coordinated plan to meet both MISO and the members' intentions, but also for SPP to have a portfolio developed that addresses needs along the seam through a series of flowgates that help us to run the market more efficiently," he said.

Cathey said he would be able to bring a more details to the SSC's December meeting.

Under the terms of a settlement agreement reached in 2015, MISO's flows on the contract path are capped at 3,000 MW north to south and 2,500 MW in the opposite direction. MISO compensates SPP and six independent transmission owners party to the agreement — Southern Co., Tennessee Valley Authority, Associated Electric Cooperative Inc., Louisville Gas and Electric, Kentucky Utilities and PowerSouth Energy Cooperative — by applying a capacity factor for flows exceeding the previous 1,000-MW contract path in the RTOs' joint operating agreement.

The settlement agreement expires in January 2021. At that time, the parties can give notice to terminate or revisit the settlement provisions. FERC approved the settlement in 2016. (See *FERC OKs MISO-SPP Transmission Settlement*.)

RSC-OMS Liaison Group Looks for Answers

Adam McKinnie, an economist with the Missouri Public Service Commission, said SPP and MISO state regulators have gathered initial feedback on the RTOs' interregional planning processes and will spend the next couple of months evaluating that input.

Commissioners on SPP's Regional State Committee plan to attend the Organization of MISO States meeting Oct. 24 in New Orleans. The SPP RSC-OMS Liaison Committee will also meet Nov. 17 in San Antonio during the first day of the National Association of Regulatory Utility Commissioners' annual meeting, McKinnie said.

The Liaison Committee has commissioned an independent analysis to determine whether the RTOs are leaving efficiencies and benefits behind in their interregional planning processes. (See *MISO, SPP States Ponder Look at Interregional Planning*.)

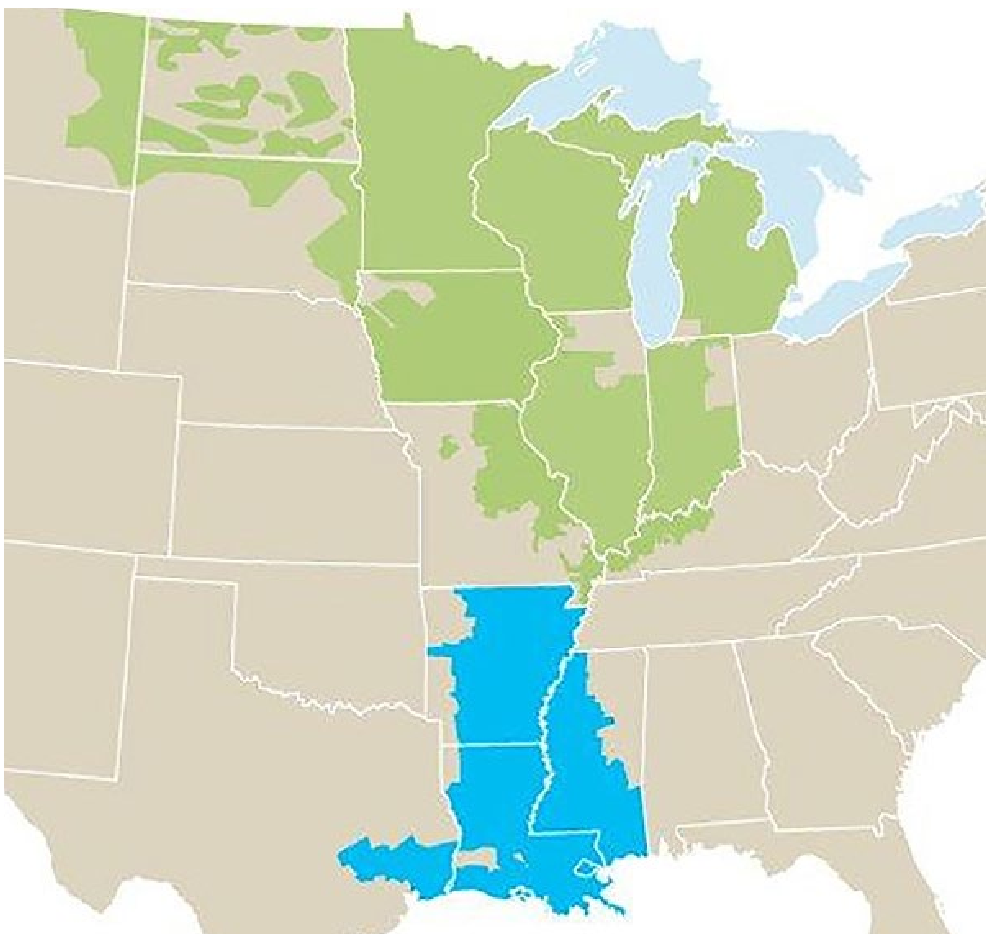
Stakeholders *responded* to a request for information in September. Eight of the 14 stakeholders who submitted responses believe an interregional planning analysis will help the committee. Three others suggested additional work on current processes.

Stakeholders have been frustrated by the RTOs' interregional work, which has yet to result in a joint project.

The commissioners "are looking for information to see what the effects would be from different changes," McKinnie said. "They didn't start with a solution. They said, 'Hey, we need information.'"

The committee has also asked the RTOs' market monitors to study the grid operators' markets and operations issues. That work will be delivered by the end of November. ■

— Tom Kleckner



MISO Midwest and South footprints | *MISO*

SPP News

SPP Cracks 70% Renewable Penetration

Bruce Rew, SPP's senior vice president of operations, predicted a year ago that there was "a good chance" the RTO would reach the 70% barrier for renewable energy penetration.

Rew's prognostication skills are not in doubt. The RTO *tweeted* last week that it met 73.67% of its demand Wednesday with wind, hydro and other non-fossil resources.

The mark came at 2:14 a.m. CT, when SPP's load was 22.5 GW. Renewable resources suppled 16.5 GW of that power, with wind supplying 65.4% and hydro 8.3%. The grid operator also set a record for wind generation on Sept. 30, when it produced 17,109 MW at 12:30 a.m. That broke the previous mark of 16,972 MW, set Sept. 11.

ERCOT, which has 22,313 MW of installed wind capacity, holds the RTO high for wind generation, set in January at 19,672 MW.

— Tom Kleckner

| *SPP*

Company Briefs

PPL in Merger Talks with Avangrid

U.S. utility companies Avangrid and PPL are in talks to combine their business, the Financial Times *reported* Monday, citing people familiar with the matter.

The Times reported it was unclear whether a deal would include an investment from Spanish utility Iberdrola, which owns more than 80% of Avangrid. The deal would be ranked as the biggest utility tie-up this year and could create one of the largest publicly traded utilities in the U.S. if it goes through, the report said.

PPL spokesman Ryan Hill told The Morning Call that the company doesn't respond to "market rumors."

More: *Reuters*; *The Morning Call*

Shell Acquires Renewables-only Power Retailer in UK

Royal Dutch Shell acquired another customer-facing electricity and gas provider in the U.K., potentially bolstering its green credentials and renewables procurement expertise in the country.

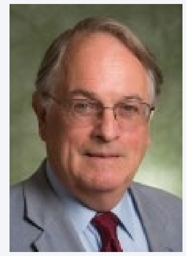
The deal for Hudson Energy will add 200,000 new customers for Shell Energy, Shell's retail provider. Hudson's supply is drawn entirely from renewable generation, while Shell depends heavily on offsets for its renewable offerings.

"As part of our ambition to build a significant U.K. retail energy business, this deal will take the number of Shell Energy Retail's U.K. residential customers to just under 1 million and adds to Shell's presence in the B2B market," said Colin Crooks, CEO of Shell Energy Retail.

More: *Greentech Media*

Nobel Prize in Chemistry Awarded for Rechargeable Lithium-ion Batteries

The Nobel Prize in chemistry was awarded Wednesday to John B. Goodenough, M. **Stanley Whittingham** and Akira Yoshino for the development of lithium-ion batteries.



Whittingham, born in the U.K. and a professor at Binghamton University in New York, was recruited to work at Exxon in the 1970s. While investigating materials able to hold particles in atom-size gaps, he discovered that titanium disulfide houses lithium ions.

German-born Goodenough, a 97-year-old engineering professor at the University of Texas at Austin, is the oldest person to receive a Nobel Prize. He improved the batteries in 1980 by swapping out titanium disulfide, in the cathode end of the batteries, for cobalt oxide. Yoshino, of Meijo University in Nagoya, Japan, developed the first commercial lithium-ion battery five years later when he made another swap: This time, exchanging reactive lithium in the anode for a carbon-based material, petroleum coke.

More: *The Washington Post*

Federal Briefs

Democrats Subpoena Perry for Documents in Impeachment Inquiry

House Democrats issued a subpoena on Thursday to Energy Secretary Rick Perry as part of their impeachment inquiry.

The subpoena demands a series of documents related to Perry's knowledge of President Trump's July 25 phone call with Ukrainian President Volodymyr Zelensky, during which Trump pushed his counterpart to investigate former Vice President Joe Biden.

Three House committees investigating the episode note that Perry reportedly encouraged Trump to make the phone call. They also want information about whether Perry sought to press the Ukrainian government to make changes to the advisory board of its state-owned oil and gas company, Naftogaz.

More: *POLITICO*

Senate Democrats Seek to Reverse ACE Rule

Senate Democrats will in the coming weeks attempt to reverse the Trump administration's Affordable Clean Energy Rule, the replacement for the Obama administration's Clean Power Plan.

The vote will be part of a series under the Congressional Review Act — which allows Congress to overturn by a simple majority regulations issued in the past 60 days — to reverse several Trump administration regulations, including those related to taxation and health care. The votes will likely be more of a political exercise, putting pressure on vulnerable GOP senators to break from the party line or face Democratic attacks over the next year of campaigning.

"The EPA has abdicated its responsibility in promulgating this deeply flawed rule, and the Senate will abdicate its responsibility if it fails to repeal the ACE rule," Sen. Ben Cardin (D-Md.) said.

More: *POLITICO*

Feds Investigating Blackjewel for Fraud

A court document filed on Oct. 5 revealed the federal government has been investigating coal operator Blackjewel for potential fraud since before the company filed for bankruptcy. The news comes after a federal judge approved the sale of two Wyoming coal mines to Eagle Specialty Materials.

The federal government asked the West Virginia federal bankruptcy court to delay discharging Blackjewel of its debts so it could continue investigating possible violations of the False Claims Act. The law holds corporations that defraud the government liable.

The investigation will likely not affect the purchase of Eagle Butte and Belle Ayr mines, but the government will probably not be able to recover the $50 million owed in royalties and rent. About half of federal mineral royalties flow back to Wyoming.

According to the sales agreement, the new owner will acquire the mines free and clear of most outstanding debt obligations.

More: *Casper Star-Tribune*

State Briefs

IDAHO

Avista Announces Settlement in Rate Case

Avista Utilities has reached a settlement with stakeholders that would decrease annual billed electric revenues by $7.18 million, it announced last week.

Under the settlement, the average customer would see a decrease of 86 cents in their monthly bill. The utility said the settlement supports its efforts to maintain and invest in infrastructure while earning a fair return.

As part of the settlement, Avista would fund a new $1.6 million program for energy savings projects in the northern part of the state.

More: *The Spokesman-Review*

KANSAS

KCC Allows Evergy to Designate Divisions

The Corporation Commission last week approved the renaming of three longstanding utility companies folded into the Evergy conglomerate created last year.

The commission agreed with the company's request to designate Kansas City Power & Light as Evergy Metro, Westar Energy as Evergy Kansas Central and Kansas Gas & Electric as Evergy Kansas South. The changes in regulatory documents will be undertaken by Evergy over a six-month period.

Evergy emerged in 2018 through combination of Great Plains Energy, the parent of KCP&L, and Topeka-based Westar Energy, which owned KG&E.

More: *Salina Journal*

MASSACHUSETTS

Boston Mayor Releases Plan to Accelerate Carbon Goal

Boston Mayor **Marty Walsh** updated the city's climate action plan last week, aiming to significantly cut carbon emissions from buildings, which account for about 70% of citywide emissions, as part of the city's effort to be carbon-neutral by 2050.

Walsh said going forward, all new city-owned buildings will be designed to be carbon-neutral, which the plan defines as releasing no net carbon emissions on an annual basis. He also plans to transition the city's vehicle fleet to low-emission vehicles and develop new guidelines for city-backed affordable housing projects with climate change in mind.

"Climate change is the defining challenge of our time," Walsh said. "As a coastal city, Boston is at the frontlines of this global crisis. While national action is at a standstill, cities like Boston are leading with plans, solutions and results."

More: *The Associated Press*

State Investigating National Grid's Management

The Department of Public Utilities has ordered an investigation into the management of National Grid in a move that stems from concerns that one of the state's largest electricity providers failed to communicate the potential for severe delays in solar power installations.

The independent management audit was ordered as part of a decision issued late last month in which the department approved a $90.4 million increase in National Grid's base distribution rates. The regulators said the rare, but not unprecedented, audit is necessary to examine "potential management problems through to the highest levels of the organization."

The approved increase was $41.8 million less than what National Grid requested. The department also approved an increase in the monthly residential fee to $7 from $5.50. However, regulators were "troubled" that the company had not informed them of the potential for a major study of transmission infrastructure in the central and western parts of the state. The decision said the "cluster study" has the potential to delay the interconnection of 900 MW of solar power, which is more than half of the state's target for solar development under the renewable energy program, anywhere from one to two years.

More: *State House News Service*

MICHIGAN

Consumers Energy to Buy Planned Wind Farm in Hillsdale County

Consumers Energy has received Public Service Commission approval to purchase a 166-MW wind farm in Hillsdale County and recover the full costs through future rate hikes.

Under the plan, Crescent Wind would design, engineer, build, start up and test the project. When completed, Consumers would purchase the wind farm for an undisclosed price. The farm is expected to go online before Dec. 31, 2020.

Consumers said the project would have a 31-year levelized cost of energy of approximately $48/MWh, but only if the company qualifies for the full value of the federal production tax credit. It also said the installed cost is $1,506/kW.

More: *Crain's Detroit Business*

OHIO

FirstEnergy to Fix Seven Hills Power Outage Issues

FirstEnergy last week said it is spending about $150,000 for a reconductoring project that includes the installation of new underground cables in the northeast corner of Seven Hills.

The project, which includes moving the service point from Graydon Drive to North Crossview Road, is currently under construction and is expected to be completed in December.

"It's very important because Seven Hills north of Rockside Road has been experiencing reliability issues," City Council President Anthony D. Biasiotta said. "That neighborhood is losing power at a much greater frequency than surrounding areas. This summer, we saw an uptick of issues that weren't storm related. Residents would lose power, the length of which would vary. Sometimes it would be for a few seconds, and other times it could be half a day or more."

More: *Cleveland.com*

OKLAHOMA

OCC Approves Settlement Agreement on Empire Rate Case

The Corporation Commission approved a settlement agreement that will keep Empire District Electric rates steady for the next year.

The company originally asked the commission for approval of a $2.3 million rate increase, but it approved $1.4 million. While the agreement keeps rates stable for the first 12 months, customers can expect to see increases each of the following two years as the utility aims to meet costs. According to an Empire executive, the agreement will provide the utility with a return on equity of 9.5%.

More: *The Oklahoman*

WYOMING

Wind Developer to Pay $3.1M to Local Governments

The Department of Environmental Quality's Industrial Siting Council last week ordered Canada-based BluEarth Renewables to contribute $3.1 million to the governments of Rock River, Laramie and Albany counties to offset the impact on public services created by a $1 billion wind project on the border of Albany and Carbon counties.

Rock River will receive $1.6 million, Laramie will receive $662,883, and Albany will receive $885,600. Monthly payments are scheduled to begin by April 2021 and should be completed in July 2023.

The project is expected to generate $52.1 million in sales and use taxes and $7.8 million in property taxes from 2021 to 2023. However, the state wind tax will provide just $2.56 million in revenue for the state's general fund during the entire life of the project.

More: *Laramie Boomerang*