RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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Entergy Touts Restoration as NOLA Leaders Question Lack of Blackstart Service

By Amanda Durish Cook

A week after Hurricane Ida clobbered Louisiana, Entergy leadership said Monday that "near-miraculous" restoration work had returned power to 70% of New Orleans.

Entergy Louisiana CEO Phillip May said the utility had *restored* power "and a sense of normalcy" to 54% of the 948,000 total customers who lost power across Louisiana and Mississippi.

But for customers in outlying Bayou areas, most of September could be spent without electricity. Entergy said it could be Sept. 29 *until* the Lower Jefferson, Lafourche, Plaquemines, St. Charles and Terrebonne parishes regain power.

"In the hardest hit region, it's going to be a rebuild, not a repair," May *again* stressed in a

Entergy's New Orleans Power station was brought online in May 2020. | *Entergy*

Sept. 6 press call. "There is considerable damage as you get into the Bayou region."

May said Ida was "one of the most destructive hurricanes to ever strike U.S. soil," packing

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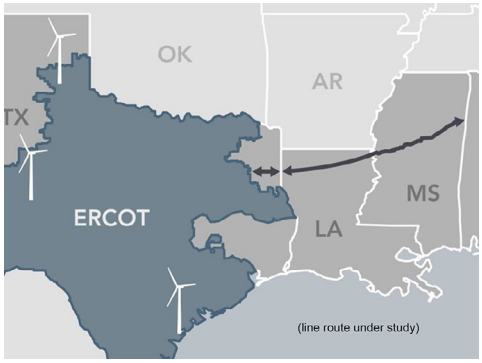
Texas PUC Considers Adding Grid Interconnections

Southern Cross Transmission Project Prime Example of New View

By Tom Kleckner

The times, they may be a-changing in Texas, where the Public Utility Commission is considering expanding DC ties with neighboring grid operators following February's devasting winter storm.



The Southern Cross Transmission project will run more than 400 miles from East Texas into SERC. | *Pattern Energy*

Texas regulators have long jealously protected the ERCOT grid's electrons from mingling with those of its neighbors. The result is a grid isolated from the Eastern and Western Interconnections and exempt from FERC jurisdiction.

"Obviously, protecting our ERCOT market from FERC jurisdiction has been of upmost importance for the commission, historically," Commissioner Lori Cobos said during the Thursday open meeting.

The Texas grid has two DC ties with SPP and a third with Mexico, but they are limited to a combined 1.1 GW of capacity and are primarily used for commercial purposes. ERCOT

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ERCOT: Sufficient Capacity to Meet Fall Demand (p.7)

CEC Looks at Gas for Midterm Reliability

By Hudson Sangree

In two workshops Aug. 30, the California Energy Commission examined the role of natural gas in the energy mix through the middle of this decade as the state's last nuclear plant retires, older gas plants close and the grid relies more heavily on renewables and storage.

In the morning *session*, CEC commissioners and analysts addressed the question of whether the state needs additional thermal generation, including incremental boosts to existing gas plants, to meet reliability challenges from 2022 to 2026.

The short answer was 'no' but with caveats and contingencies.

Hotter summers with strained supply make conditions more difficult to predict, lead

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Calif. Wants to Turn More Waste into Gas (p.3)

PG&E Value Lags as Dixie Fire Rages (p.5)

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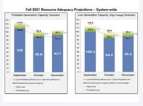

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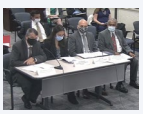

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In this week's issue

***NetZero Insider* is now live!**
See p.14 for this week's coverage.

CAISO/West News

Calif. Wants to Turn More Waste into Gas

Wildfire Tree Clearing Could Feed Anaerobic Digesters

By Hudson Sangree

California is trying to figure out how to incorporate renewable natural gas into its clean energy mix while diverting millions of tons of methane-emitting organic waste from its landfills.

Renewable natural gas (RNG) — produced from landfills, dairies and dead trees — is disfavored by many environmentalists because of its un-green sources. But RNG is likely to play a larger role in California as the state tries to drastically reduce greenhouse gases and rely on 100% clean energy by 2045.

It can power vehicles, heat homes and run cooktops using existing gas pipelines and household appliances.

Sam Wade, Coalition for Renewable Natural Gas | *California Energy Commission*

"We're fine being the bridesmaid and not the bride, but at the end of the day we think we will be utilized in a low-carbon future," Sam Wade, public policy director for the Coalition for Renewable Natural Gas, told a California Energy Commission workshop on RNG Tuesday. "When you design your policies to move things around and be flexible, we're a very flexible resource that can be used anywhere conventional gas is used."

Others made the case that renewable natural gas (RNG) is a way to deal with the huge amounts of methane from the state's large commercial dairies and landfills, which together produce 75% of methane emissions statewide, according to the California Air Resources Board.

Dairies produce 54% of methane emissions; landfills account for 21%. Wastewater treatment, another source of renewable natural gas, represents about 3% of methane emissions in California.

Senate Bill 1440, adopted in 2018, requires the California Public Utilities Commission to "consider adopting specific biomethane procurement targets or goals for each gas corporation so that each … procures a proportionate share … of biomethane annually." The state's two largest gas corporations under CPUC jurisdiction are Southern California Gas and Pacific Gas and Electric.

Karin Sung, CPUC | *California Energy Commission*

CPUC Senior Energy Analyst Karin Sung said CPUC staff have proposed targets under SB 1440 that would require the gas companies to procure enough biomethane to divert an additional 8 million tons of organic waste by 2025. Most of the waste would be from compost and chipping and grinding of trees and other vegetation.

Under the plan, utilities would have to procure 75.5 million MMBtus of renewable natural gas by 2030 to support the state's waste diversion goals, Sung said.

The state has well-established programs to help dairies stop methane leaks, and about 154 wastewater treatment plants around the state have biodigesters, so "the biggest slice of the pie here that's remaining is landfills," she said.

State law requires landfills to capture or destroy methane, including through burning the gas to break it down, but landfills continue to emit large quantities of methane.

Super Emitters

NASA's Jet Propulsion Laboratory in Southern California has developed methods to pinpoint and measure methane and carbon dioxide "point sources" from airborne surveys. NASA researchers identified 30 large landfills as producing 40% of the total point-source emissions detected in their survey of more than 300,000 industrial facilities, dairies and landfills.

NASA said the "super emitter" landfills showed huge plumes of methane, a potent greenhouse gas that, like carbon dioxide, traps heat in the atmosphere, "but it does so more efficiently and for a shorter period of time" than CO_2, the space agency said.

That's why the CPUC is targeting landfills for new biodigesters or expanded digester capacity, Sung said.

There are now nine standalone anaerobic digestion plants in California to turn waste into usable gas, eight of which have expansion plans, she said. More than 150 wastewater treatment plants also have digesters that could handle more waste.

The state's CalRecycles program requires processing 10 million tons of organic waste by 2025. Adding another 8 million tons under the CPUC proposal would mean diverting a total of 18 million tons of waste in the next four years, which is beyond current capacity.

"That's where we step in," Sung said.

The CPUC has proposed the state's four largest investor-owned utilities establish a cost-effectiveness test to "guide procurement decisions through a jointly filed Standard Biomethane Procurement Methodology," requiring CPUC approval.

Boosting capacity and building new plants will likely require passing costs on to gas ratepayers, so ensuring cost-effectiveness is essential, Sung said. Making sure the digesters can produce gas of pipeline quality is another concern. Reducing the impact of landfills on low-income communities is vital, too, she said.

The digesters could also help the state deal with the vast quantities of dead timber from wildfires and the vegetation from tree-clearing efforts along thousands of miles of power lines, Sung said.

"When you think of woody biomass, it's more than just the wood itself," she said. "It also the grasses and invasive species — anything that we can do to help support and prevent additional wildfires."

The black carbon from those fires, which has far exceeded any other state pollutants in recent years, is another target of GHG reductions, she said. ■

An anaerobic digestion plant in San Luis Obispo, Calif., produces RNG from food and green waste. | *Hitachi Zosen Inova*

CAISO/West News

CEC Looks at Gas for Midterm Reliability

Continued from page 1

Commissioner Siva Gunda said. Last summer's rolling blackouts and this summer's near misses are examples, he said.

"As we have seen last year and this year, heat waves and droughts are posing much more substantial impacts on demand and supply," Gunda said. "This makes a look ahead much more challenging."

California has experienced problems during Western heat waves in the evening hours, when solar ramped down and imports dried up.

"How do we plan for contingencies in the extreme events that might be significantly beyond [traditional] planning assumptions?" Gunda said. "As most of us know, the critical issue to address in the midterm is really the reliability during the net peak time that offers both ramping and dispatch uncertainties."

"This workshop is a first step to frame the question and develop a dialogue around this important question in an open, transparent and robust way," he said.

California Public Utilities Commissioner Clifford Rechtschaffen noted that the CPUC's decision to order utilities to procure an additional 11.5 GW by mid-decade "teed up" the issue but skipped the question of whether more gas generation might be needed. (See *CPUC Orders Additional 11.5 GW but No Gas*.)

"We left open in that ruling whether and to what extent we should authorize procurement from any natural gas resources pending further review, including this analysis from the Energy Commission," Rechtschaffen said. "So while we're here today, the work will help inform that decision whether there's a need for additional procurement for reliability through 2026, and whether any fossil resources should be should be considered."

No More Gas Needed, Probably

To answer those questions, CEC staff members broke down their analysis into several tracks, said Liz Gill, adviser to Gunda. The first track dealt with a technical analysis evaluating midterm capacity needs and evaluating thermal capacity needs.

Do "incremental thermal resources provide an additional reliability benefit compared to a portfolio of preferred resources [mainly renewables and storage]?" Gill said.

The CEC's demand forecasts informed the analysis. In the *second* workshop of the day, CEC staff looked at expected gas demand through 2035. Pacific Gas and Electric and Southern California Gas, the state's two largest suppliers, each predict a 1% decline in the next 14 years, though extreme weather could alter that forecast, the utilities said.

More importantly, the CEC's examination considered the expected rollout of thousands of megawatts of battery storage in the coming years.

The state went from having 126 MW of battery capacity last year to 1 GW this summer, CEC staff said. More than 10 GW may eventually be connected to the ISO's grid.

The CEC looked at the potential problems of that rollout, which have already included delays in the supply chain and booked-up manufacturers.

"And so, [we] asked, what are the potential risks with battery deployment and performance?" Gill said. That evaluation is ongoing.

The CEC's Mark Kootstra presented the technical analysis, which concluded that summer 2022 remains a problem.

An emergency declaration by Gov. Gavin Newsom earlier this year cited a potential 5,000 MW capacity shortfall next year. (See *Calif. Governor Proclaims Emergency as Blackouts Loom*.)

After that however, the state should be in better shape as more renewables and storage connect to the grid. By the end of 2022, about 5,000 to 6,000 MW of nameplate capacity resources are scheduled to come online, he said.

"Assuming we haven't had any gas retirements beyond what's considered in the analysis, the preferred system plan significantly diminishes the concerns for reliability from 2022 through 2026," he said. The CPUC's procurement orders "should be sufficient to diminish that reliability concern from 2023 on."

He warned that unexpected contingencies could arise as they did in last summer's heat waves and this year when a wildfire derated a major transmission line from the Pacific Northwest. (See *CAISO Declares Emergency as Fire Derates Major Tx Lines*.)

"We're not out of the woods," Kootstra said. "There could still be ... contingencies. But I think overall, the planning is in good shape." ■

The planned closure of California's last nuclear plant at Diablo Canyon is prompting reliability concerns. | *PGE*

CAISO/West News

PG&E Value Lags as Dixie Fire Rages

Wildfire Victims' Trust is Short $2.5 Billion Because of Stock Price

By Hudson Sangree

The value of Pacific Gas and Electric's (NYSE:PCG) fire victims trust fund has suffered from news that the utility's equipment started fires last year and may have ignited the single largest blaze in California history this year, leading its trustee to warn victims that they may not receive the full value of their claims.

The fire victims trust, established on July 1, 2020, is $2.5 billion short of expectations, retired state appellate court Justice John Trotter wrote to victims of PG&E-caused fires in 2015, 2017 and 2018 on Wednesday.

Part of PG&E's bankruptcy reorganization, the settlement "is unique in that its value was not a true lump sum but rather a combination of cash and PG&E stock," Trotter noted. "It was reported to be $13.5 billion, $6.75 billion in cash and $6.75 billion in stock value. However, that never materialized.

"On the day the trust was established and became owners of approximately 477 million shares of PG&E stock, it was trading at $9 per share, for a value of $4.2 billion, approximately $2.5 billion less than promised. Over the last year, that value has fluctuated and today is close to its value" when the trust was funded, Trotter wrote.

The Dixie Fire has a lot to do with the predicament. By Sunday it had spread to 1,400 square miles, larger than the land mass of Rhode Island or Yosemite National Park. Only last year's August Complex of fires in Northern California, which topped more than 1 million acres, *exceeded* the Dixie Fire's current size. The California Department of Forestry and Fire Protection (Cal Fire) is investigating a PG&E power line as the possible cause of the Dixie Fire.

PG&E stock, which closed at $10.34/share on the day the trust fund was established, has remained below $13 since then. It closed at $9.79 on July 16, before the company informed the California Public Utilities Commission that it may have been responsible for the Dixie Fire. (See *PG&E Says Its Line May Have Started Dixie Fire*.) Shares closed at $9.15 on Friday.

As of Aug. 31, the trust fund had *awarded* $2.4 billion in determination notices and made payments of almost $740 million.

Meanwhile, PG&E said last week it had secured approval from the PUC to sell its San Francisco headquarters for $800 million and to return $400 million to ratepayers to lower their bills. PG&E announced in March it was moving across the San Francisco Bay to new headquarters in Oakland. (See *PG&E to Sell San Francisco HQ for $800M*.)

"In addition to promoting long-term savings for PG&E, the sale of our San Francisco headquarters will help to offset future customer rates at a time when we're making significant safety and operational investments," CEO Patti Poppe said in a *statement*.

In August, the utility *asked* the CPUC to increase its return on equity from 10.25% to 11% next year, which could increase its profits by $200 million.

The company also announced it would donate $1 million this year to wildfire relief and recovery efforts, including $300,000 to the American Red Cross and $100,000 "to assist communities impacted by the Caldor Fire in El Dorado County."

The cause of the Caldor Fire, which forced the evacuation of the city of South Lake Tahoe last week, is under investigation.

"We all are blessed by the kindness of the many nonprofit organizations, volunteer fire departments, and community groups that are opening their hearts and rolling up their sleeves in service to those who have been displaced temporarily or permanently by these terrible fires," Poppe said in the statement.

It made no mention of the Dixie Fire or the Zogg Fire, which Cal Fire concluded was started by a tree falling on a PG&E power line. The Zogg Fire killed four people, including a mother and her young daughter unable to escape the flames, in rural Shasta County. (See *PG&E Equipment Started Zogg Fire, Investigation Finds*.)

If Cal Fire finds a PG&E line started the Dixie Fire, it would mark the fifth year in a row that PG&E's equipment has been blamed for catastrophic blazes.

Cal Fire blamed the utility's equipment for starting the devastating Northern California wine country fires of October 2017; the Camp Fire, which killed 85 people and leveled the town of Paradise, in November 2018; and the Kincade Fire, which tore through Sonoma County in October 2019.

The company filed for bankruptcy protection in January 2019 and emerged from Chapter 11 proceedings in June 2020, after agreeing to pay a total of $25.5 billion to fire victims, insurance companies and local governments for the 2015 Butte Fire, the wine country fires and the Camp Fire.

The insurance companies and governments received cash; only fire victims got stock — receiving more than one fifth of PG&E's outstanding shares,

Before the wine country fires of October 2017, PG&E stock sold at more than $70/share, giving it a market capitalization of $36 billion. The current share price puts the utility's market value at approximately $20.6 billion. ■

Firefighting aircraft attacked the Dixie Fire on Horton Ridge in the blaze's southeast area last week. | *U.S. Forest Service*

CAISO/West News

NV Energy Applies to Build Northern Nev. Line

By Elaine Goodman

NV Energy filed an application last week to build a 235-mile transmission line across northern Nevada — a $901 million project that would complete a transmission triangle around the state.

The Greenlink North project would run from Robinson Summit near Ely in eastern Nevada, to Fort Churchill near Yerington.

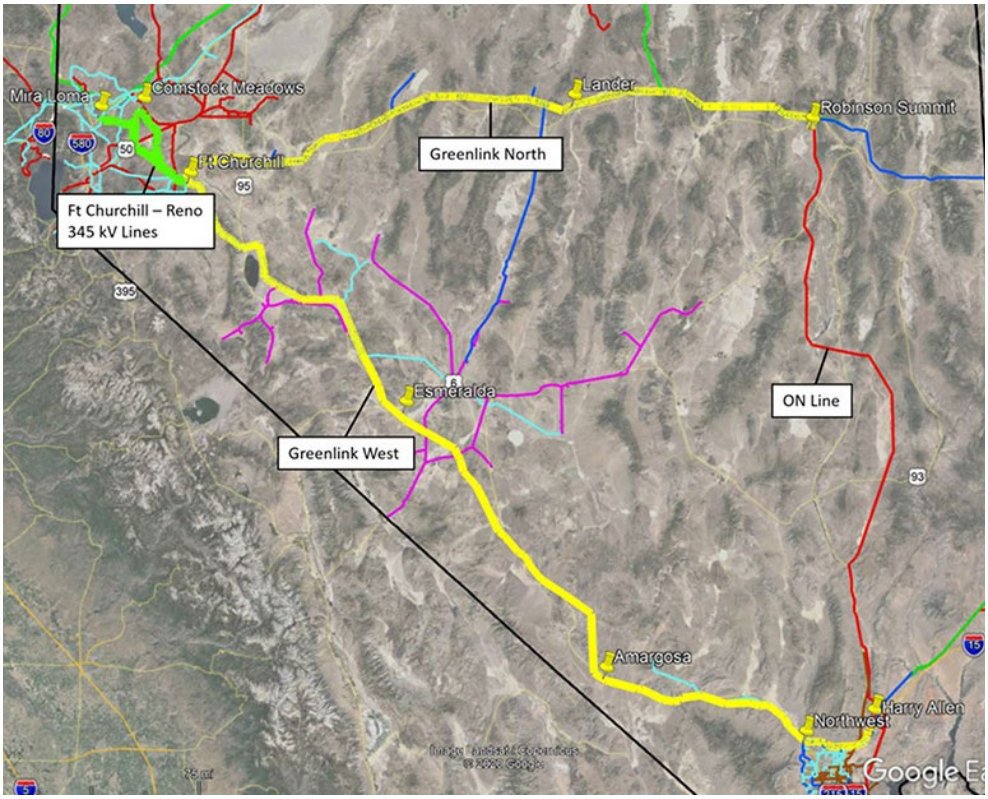
The 525-kV transmission line would ultimately connect NV Energy's existing One Nevada line, which runs down the east side of the state, to Greenlink West, a yet-to-be-built line along the west side of the state. Greenlink West and One Nevada will meet in the Las Vegas region.

The Public Utilities Commission of Nevada in March approved construction of Greenlink West. NV Energy expects construction to be completed by the end of 2026.

In its application to build Greenlink North, NV Energy said its renewable portfolio has relied heavily on solar resources in Clark County because of transmission constraints.

"The presence of Greenlink North opens vast areas to other renewable energy resource development, as well as new geographically diverse solar resources," the company said.

The Greenlink project will also increase electric reliability throughout Nevada, create jobs and help the state's economy recover from the impacts of the COVID-19 pandemic, NV Energy said in a *news release*.



NV Energy's proposed Greenlink North line would help create a transmission triangle throughout Nevada. | *NV Energy*

Legislative Mandate

NV Energy filed its application for Greenlink North last week as an amendment to the utility's 2021 integrated resource plan. The transmission proposal is also called the Transmission Infrastructure for a Clean Energy Economy Plan (TICEEP).

NV Energy was required to file the TICEEP by Sept. 1 as part of Senate Bill 448, a wide-ranging energy bill that the state legislature passed in May. And SB448 requires the PUCN to accept the TICEEP as long as it meets certain requirements. (See *Far-reaching Energy Bill Sweeps Through Nev. Legislature*.)

Sen. Chris Brooks (D), who introduced *SB448*, said previously that one of the bill's goals was to speed up completion of the Greenlink network, which in turn could spur other transmission projects.

Although the PUCN in March approved conceptual designs, permitting and land acquisition for Greenlink North, Brooks said SB448 adds certainty that construction of the project will be approved. The goal is to have Greenlink North in service by Dec. 31, 2028.

Meeting Demand

TICEEP includes another transmission component specified by SB448: a 32-mile, 525-kV line just north of Las Vegas. The line will follow an existing transmission path from the Harry Allen substation to the Northwest substation, through a federally designated renewable energy transmission corridor.

NV Energy said the line would potentially allow a second 525/230-kV transformer at the Northwest substation to serve increased demand in Las Vegas. The new line would also give the Las Vegas area greater access to renewable resources, the utility said.

"Without this line, new solar and geothermal resources located near Greenlink West may be constrained due to transmission limitations into the Las Vegas Valley, thereby impeding development of those renewable resources," NV Energy said in its filing.

The utility estimated the cost of the Harry Allen to Northwest line at $143 million.

NV Energy noted in its filing that its proposal does not analyze alternatives to Greenlink North and the Harry Allen to Northwest segment because the legislature directed the utility to evaluate only the two projects.

RTO Mandate

Another section of SB448 will require transmission providers in Nevada to join a regional transmission organization by Jan. 1, 2030, unless the provider can show that such a move isn't feasible.

NV Energy said in its filing that it plans to participate in a task force that will evaluate potential benefits of joining an RTO.

"[NV Energy] will continue to explore energy market possibilities that could benefit their customers and the state of Nevada," the utility said. "However, it is too early to make any recommendation to joining an RTO." ■

ERCOT News

ERCOT: Sufficient Capacity to Meet Fall Demand

By Tom Kleckner

ERCOT quietly released its final *resource adequacy assessment* for the fall season Friday, saying it has sufficient installed generating capacity to serve peak demand under normal system conditions and several risk scenarios.

The grid operator expects a seasonal peak demand of 62.7 GW, unchanged from its preliminary fall seasonal assessment of resource adequacy (SARA), including 120 MW of forecast load reduction from rooftop solar.

The report was dropped in a *market notice* without the normal press release and media call. Going forward, ERCOT said it will eliminate the preliminary SARAs and publish only a final assessment.

A coal plant's extended outage has cut reserve capacity by 868 MW since the preliminary fall SARA was released in May. However, ERCOT is expecting an additional 5.3 GW in planned gas, wind and solar capacity to be available to meet fall demand. It is also counting on another 644 MW of battery energy storage capacity to be available, though it is assumed to provide ancillary services.

ERCOT expects 14.8 GW of thermal outages during the fall season (October and November), based on historical outage data from the past three years.

The grid operator said a change in how it categorizes an "unavoidable extension" resulted in an increase in projected unplanned outages (previously called forced outages) and a decrease in planned outages (previously called maintenance outages). With the change, ERCOT said, unplanned outages increased for the high and extreme unplanned outage cases.

Beginning with this SARA, the grid operator expanded the low-wind output scenario to include low-solar output. It also includes an analysis of extreme scenarios that assume multiple severe system conditions occur. tERCOT said the report is intended to illustrate the range of resource adequacy outcomes that might occur. Staff studied high peak load scenarios with high and extreme generation outages and expected and low renewable output. They said load shed becomes a possibility when unplanned outages exceed their normal 10-GW threshold, combined with low renewable output.

Summer Peak Falls Short of Record

The Texas grid operator set a pair of new demand peaks last week as a late-summer heat dome settled over the state.

ERCOT set a new demand mark for September of 72.2 GW during the month's first day, breaking a two-year old mark, Kristi Hobbs, the grid operator's vice president of corporate strategy and Public Utility Commission relations, told the PUC Thursday. Wind and solar energy each produced about 5 GW during the peak.

Demand on the Texas grid reached a summer high of 73.5 GW on Aug. 31. Staff had projected a record peak of 77.1 GW this summer, but the August 2019 record of 74.8 GW stills stands. ■

ERCOT is expecting more than 600 MW of energy storage, similar to Broad Reach Power's Odessa project in West Texas, to provide mostly ancillary services this fall. | *Broad Reach Power*

ERCOT News

Texas PUC Considers Adding Grid Interconnections

Southern Cross Transmission Project Prime Example of New View

Continued from page 1

uses the same ties to exchange power with its neighbors during emergency conditions.

But there may be another option: Pattern Energy's Southern Cross Transmission merchant project, a bi-directional HVDC transmission line that will asynchronously connect ERCOT with systems in the SERC Reliability region. The 400-mile, double-circuit 345-kV line will be capable of carrying 2 GW of power between Texas and SERC, enough to have possibly made a difference during the February storm.

"Winter Storm Uri, opened our eyes to the challenges that come from our isolation," said Cratylus Advisors principal Mark Bruce, who represents Pattern before ERCOT and the PUC and calls Southern Cross "a gift to the state of Texas."

"The Southern Cross project will be funded entirely by private capital and those costs will be recovered exclusively from the wholesale power traders who use the facility," Bruce told *RTO Insider*. "Absolutely no costs of the project will be included in Texas transmission rates."

The project has FERC approval and a waiver from the commission's jurisdiction. It also has a certificate of convenience and necessity, granted by the PUC in 2017 to Garland Power & Light, which owns the project's western endpoint.

The developers are working with ERCOT to respond to *14 PUC directives* to determine whether DC ties should be economically dispatched or subject to a congestion-management plan (*46304*). Half of the directives have been completed, Bruce said. (See "Members Debate Southern Cross' Bid to be Merchant DC Tie Operator," *ERCOT Technical Advisory Committee Briefs: Feb. 22, 2018*.)

Commissioner Jimmy Glotfelty, who was among those behind Clean Line Energy Partners and its plan to ship renewable energy over HVDC lines to urban centers, spoke up for the Southern Cross project.

"I'm a fan of DC ties," he said. "If we want to continue to be the best place to do business, we're going to have to have that type of a system that is technologically advanced and reliable and economic. If DC lines are going to be part of it, and I think they should, let them be part of it."

"Pattern is pleased that this commission

The Texas PUC discusses interconnections with neighboring RTOs and speeding up ERCOT's transmission planning process during its Sept. 2 open meeting. | *Texas Admin Monitor*

ERCOT News

Mark Bruce, Cratylus Advisors | © *RTO Insider LLC*

recognizes the value of reliability benefits and the economic benefits that come from this kind of interconnection," Bruce said. "... We are excited that the commission wants to wrap this up and we are certainly willing to do our part to make it happen."

Doug Lewin, an Austin-based energy consultant, told *RTO Insider* he was "intrigued" by the commissioners "seemingly universal feeling ... that connecting to the Eastern and Western Interconnects is a good idea."

He said he agreed with other experts that ERCOT doesn't have to give up independence from FERC jurisdiction to interconnect with the other grids. He said the commission might grant a waiver "given the magnitude of the problems facing Texas last February and potentially facing us in the future."

Cobos has been leading an effort to investigate expanding current ties and adding other interconnections that don't incur FERC jurisdiction. She told her fellow commissioners that ERCOT has also studied a potential tie with MISO. Unsurprisingly to those involved in SPP's and MISO's effort to agree on interregional transmission projects, Cobos said the study turned up cost allocation and modeling "differences" between ERCOT and MISO.

Commissioner Will McAdams cited Uri in urging deeper ties with the Texas grid's neighbors.

"We need a way to build around this in case the one-in-200-year events happens ... where we can draw resources in and work through a partnership with those [RTOs]," he said.

"We can't look at these weather events as static, one time," Glotfelty said. "They are going to happen again and again."

The commissioners, who all joined the PUC since April, have begun to flex their regulatory muscle. In a *memo*, Cobos reminded the commission that they have the authority under the state's Public Utility Regulatory Act to order ERCOT to build transmission that ensures the safety and reliability of the grid.

They discussed the need for a transmission solution to congestion issues in the Rio Grande Valley. Cobos said a 345-kV line in the Valley is "double-circuit capable," but only one circuit is being used. She suggested ERCOT study adding another line and building a new 345-kV line running east to west near the border with Mexico.

"We can have ERCOT and the [transmission service providers] study those transmission solutions that are near term, low-hanging fruit, and see if it's a good idea to move forward with the transmission buildout," Cobos said. "We can get additional information from ERCOT, and we can order them to build it."

ERCOT's interim CEO, Brad Jones, released a *roadmap to grid reliability* in July that included new transmission capacity to address the Valley's limitations. The grid operator's Regional Planning Group could take up the issue during its next meeting on Sept. 15. (See *ERCOT Issues 'Roadmap to Grid Reliability'*.)

Cobos included in her memo an eight-point list of actions that could be taken to speed up ERCOT's planning process.

"If we want to use our authority, we can't let them get bogged down in [a] multi-stakeholder process at ERCOT," Glotfelty said. "It takes too long. Everyone has to have their say. It's a big market. We've got to hold their feet to the fire to get these things done."

PUC Chair Peter Lake asked Cobos to develop a process for completing the potential Rio Grande Valley projects "sooner, rather than later."

"Let's see what additional analysis is needed and the commission's authority to order the construction of these lines," he added. "We got very clear and robust direction from the legislature to solve these problems."

Lewin said the PUC's newly emboldened outlook is "long overdue." He said recent chairs have been hesitant to use their authority and "did a lot of arguing for their own limitations."

"This commission is operating in a very different context, with, as Chair Lake says, 'a bias toward action,'" Lewin said. "Texas needs new transmission, and I'm glad the commission is moving aggressively." ■

ISO-NE News

Largest Standalone Battery Storage System in Northeast Planned for Small Mass. Town

The Project Will Help Incorporate Wind, Solar Energy onto the Grid

By Emily Hayes

Plus Power, a company based in San Francisco, is proposing to build a 150-MW/300-MWh battery energy storage system south of Boston as traditional fossil fuel plants retire and renewable energy resources grow across the state.

The company filed a *petition* last week with the Massachusetts Energy Facility Siting Board for approval to build the lithium-ion battery project, called Cranberry Point Energy Storage. It will be the largest bank of standalone batteries in the region and the first of its kind in Massachusetts, according to Plus Power.

The batteries will connect to the ISO-NE transmission system, but they will be a standalone system instead of storing renewable energy generated on site.

Cranberry Point will "decrease future grid congestion in southeast Massachusetts that will be created by new solar generation onshore and the nearby integration of Vineyard Wind and Mayflower Wind offshore wind projects," Brandon Keefe, general manager of Plus Power, said in a statement to *RTO Insider*.

ISO-NE's forward capacity market auction in February brought a lot of batteries on board for the first time, with 630 MW of new and existing battery storage in total.

Plus Power is responsible for over half of that after winning bids for the Cranberry Point project in Carver, Mass., and a 175-MW/350-MWh system in Gorham, Maine.

The company expects the facilities will be operational by 2024.

Cranberry Point will operate as a generator for ISO-NE instead of delivering energy to end users through a distribution company procurement. It will absorb energy from the grid during times of low demand and release energy into the marketplace at peak hours to avoid outages in case of congestion or a lack of resources.

By storing and saving energy for peak demand hours, the project will help the grid rely less on natural gas or fossil fuel-fired plants. The Cranberry Project represents about 10% of the retiring 1,700-MW Mystic River gas generation units just north of Boston, according to Keefe.

The project is also located near the recently retired Pilgrim nuclear power station in Plymouth, Mass.

"Because the project will help displace non-renewable generating resources while reducing peak demand and system losses and increasing grid reliability, it would also be eligible to contribute to the clean peak standard," Keefe said.

The Massachusetts Clean Peak Energy Standard program provides incentives to clean energy technologies that supply electricity or reduce demand during seasonal peak periods established by the state Department of Energy Resources.

The battery storage system received approval from the town of Carver's planning board and conservation commission in 2019 and will help the state meet its goal of deploying 1,000 MWh of energy storage by 2025.

There are several controversial solar projects under development in Carver that would incorporate pole-mounted solar panels over active cranberry bogs to create more space for solar development in the northeast. But there are still questions about how the shade created by the panels will affect crop productivity or the cranberry plants.

But as plans move ahead, Plus Power expects its battery storage project to help incorporate new solar projects into the grid. Construction on the battery system will likely begin in 2023. ■

Rendering of the proposed project site for the Cranberry Point Energy Storage battery project in Carver, Mass., next to one of Eversource Energy's existing substations | *Plus Power*

ISO-NE News

NewGrid to Bring Congestion Software to ISO-NE System

Software Developer Received a $250K Grant

By Emily Hayes

The developer of software that makes the electric grid more reliable and efficient received a $250,000 grant from the Massachusetts Clean Energy Center (CEC) to begin planning for its deployment in the Northeast.

The support software, developed by NewGrid in Somerville, Mass., maps ways to reroute power on the grid to mitigate congestion and move more power.

As more renewables come online in New England, such as offshore wind, more transmission infrastructure is needed to move the electricity to demand centers. But until those transmission lines and electrical substations are built, congestion on the grid is handled like tolls on a highway — users pay a higher cost for electricity.

However, NewGrid's software technology analyzes existing infrastructure to provide options that reconfigure a new pathway for the electricity.

"We make the old grid look like a new grid every time," Pablo Ruiz, co-founder, CEO and chief technology officer of NewGrid, told *RTO Insider*.

Ruiz predicts the support software could move 40% more power on the ISO-NE grid.

He originally developed the technology at Boston University, where he is a professor of mechanical engineering, with funding from the Massachusetts Department of Energy Resources.

NewGrid was one of 23 companies to receive a grant from Mass CEC, with over $2.6 million in funding to support innovation in clean energy research.

Before the technology is deployed on the ISO-NE grid, Ruiz said he will work with the organization to hone the technology.

"Each regional operator will have different needs," he said. But the end result will allow grid operators to "take advantage of the flexibility they already have," instead of relying entirely on building new transmission infrastructure, Ruiz said.

Advancements in computational technology over the last few years can adapt and optimize the grid to be a "flexible and agile resource," Ruiz said.

Grid operators would have more of a supervising role, while the software provides options for rerouting electricity in the same way a GPS app provides options to drivers.

The software is useful "not only in real time but in planning for weeks or even months ahead" to help grid operators avoid or deal with outages, Ruiz said.

ERCOT uses a similar technology, and NewGrid is already working with National Grid in the U.K. to deploy the software.

ISO-NE said in a statement to *RTO Insider* that it is looking forward to investigating how the new technology can help mitigate the challenges of integrating renewable energy resources by automating some procedures that are now manual.

"The potential for efficiency could benefit the region, especially as more wind and solar resources are integrated onto the grid," an ISO-NE spokesperson said.

NewGrid's technology will help grid engineers "improve the decisions they make and the speed at which they make those decisions," Ruiz said. ■

NewGrid, a software developer in Somerville, Mass., will partner with ISO-NE to deploy technology that allows the electric grid to reroute power in a way that makes the grid more reliable and efficient. | *Bidgee, CC BY-SA 3.0, via Wikimedia Commons*

ISO-NE News

NEPOOL Reliability Committee Briefs

ISO-NE's Proposed ICR Shows Decrease for FCA 16

ISO-NE is proposing an installed capacity requirement (ICR) of 32,568 MW for Forward Capacity Auction 16, a 1,585-MW decrease from FCA 15, the RTO *told* the NEPOOL Reliability Committee on Wednesday.

ICR is the minimum system capacity needed according to the Northeast Power Coordinating Council reliability criteria. ISO-NE's annual calculations also account for operators' ability to purchase energy from neighboring balancing authority areas during a capacity deficiency.

The RTO also *told* the committee that the Maritimes, Hydro-Québec Phase II, Highgate, New York AC and Cross Sound Cable ties would provide a combined 1,830 MW of benefits for FCA 16, a 95-MW increase from FCA 15. Benefits from the Hydro-Québec Phase II (40) and New York AC (29) ties make up 72.6% of the additional megawatts.

ISO-NE said New York modeled behind-the-meter solar using five historical profiles (2015-2019) as opposed to the single historical profile (2006) used for FCA 15, which would have lowered the total tie benefits by 55 MW. The RTO added that using five historical profiles in FCA 16 simulations introduced more load diversity between New England and New York, resulting in higher tie benefits.

New England and New York need less simultaneous emergency assistance with increased load diversity, corresponding with higher tie benefits from Québec and the Maritimes. Hydro-Québec interconnection capability credits (HQICCs) of 923 MW — up from 883 MW last year — resulted in a net ICR of 31,645 MW, a 4.9% decrease from FCA 15. The reserve margin with the HQICCs is 16.2% and 12.9% without them.

The gross cost of new entry for the marginal reliability impact system demand curve cap for FCA 16 is calculated as $12.40/kW-month, with net CONE at $7.468/kW-month.

FCA 16 models the same zones as FCA 15: Northern New England as export-constrained with Maine nested inside, and Southeast New England as import-constrained.

The RC will vote on the ICR-related values on Sept. 21, and the Participants Committee will take up the matter on Oct. 7, ahead of a FERC filing by Nov. 9.

Additional Questions Sought for Survey

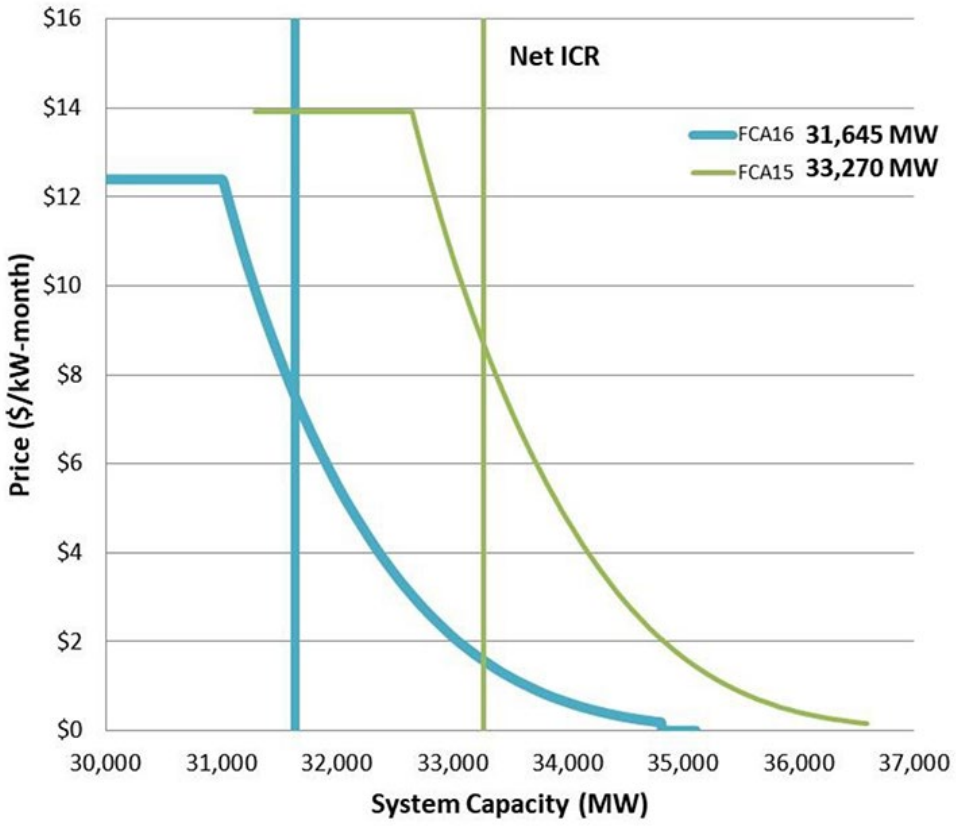
ISO-NE seeks to add questions to the winter readiness survey to enhance awareness of potential impacts on generator availability from extreme cold weather and precipitation. According to the RTO's *presentation*, the proposed questions would provide additional insight into generator capabilities, which will enhance the energy emergency forecasting and reporting process.

New questions include asking if solar and wind generators about their mechanisms for de-icing and snow removal in addition to any equipment that mitigates the impact of cold weather. In the absence of specific mechanisms and equipment, the follow-up question posed to generators is to describe why they believe those measures to be unnecessary.

The RTO wants to have the additional questions in place before distributing this year's survey, which it will send Nov. 1.

The RC will vote on the changes Sept. 21, while the PC will consider it Oct. 7. ■

— Jason York



ISO-NE is proposing a net installed capacity requirement of 33,270 MW, a 4.9% decrease from FCA 15. | *ISO-NE*

ISO-NE News

NEPOOL Stakeholders Discuss Transition Mechanisms for MOPR

By Jason York

As stakeholders and ISO-NE work to eliminate the minimum offer price rule (MOPR) from the Forward Capacity Market (FCM), the NEPOOL Markets Committee discussed multiple proposals centered on potential transitional mechanisms at a meeting last week.

The meeting was a product of four stakeholders — FirstLight Power, Calpine, Vistra and Energy Market Advisors — who agreed to delay their presentations from the Aug. 10-12 MC meeting so that Jeffrey McDonald, the RTO's vice president of market monitoring, could *provide* his opinions on the removal of the MOPR.

Solar panels in Rockland, Maine | *Crispins C. Crispian, CC BY-SA-4.0, via Wikimedia*

FirstLight

Changes to the MOPR, along with improved retirement signals and rules, would make reliability aligned with state policy goals, according to a *presentation* by FirstLight's Tom Kaslow that highlighted a revised capacity performance payments (CPP) proposal.

Market changes are needed to value the differences in energy call options each capacity seller must provide under its capacity supply obligation (CSO). That is because the value cannot, by definition, be realized through spot energy and operating reserve prices, Kaslow said. The revised CPP design defines a common strike price for all capacity resources enforced in the highest 1% of real-time LMP hours.

Capacity resources with higher strike prices would be required to buy the gap between their strike and the common strike price, with those proceeds used to compensate the resources that made the common strike value possible. Thus, the revised CPP design would complement, not replace, effective load-carrying capability (ELCC).

Calpine

ISO-NE should revise the rules for CSOs to reflect the system's needs better, regardless of what happens with the MOPR, Calpine's Brett Kruse *said* in his presentation. That would be accomplished by reducing capacity resources' combined notification, start-up and minimum run and down times to 24 hours from 72 hours.

PJM had similar cycling parameters until it changed expectations for its Capacity Performance product. Kruse noted that Calpine is not proposing PJM's parameter values, only using them to demonstrate what is possible. In addition, parameter changes typically do not require significant capital outlays, just changes in operating practices.

The resource dispatch cycle, Kruse added, would now efficiently mimic ISO-NE's dispatch cycle, making everything line up within 24 hours. The change should also fit with an upcoming capacity accreditation initiative that would allow even more fine-tuning.

Vistra

Vistra's Andrew Weinstein *floated* altering Competitive Auctions with Sponsored Policy Resources (CASPR) for a three-year transition period instead of outright eliminating the MOPR, arguing that doing the latter would not fly with FERC.

The company's proposal would reinstitute the renewable technology resource (RTR) exemption and allow bilateral transactions.

"A CASPR transition that substantially accommodates state-subsidized resources while preserving investor confidence and avoiding cost shifts could be appealing to all sides of NEPOOL, as well as both Republicans and Democrats at FERC, as a solid path forward towards a permanent solution," Vistra said.

Calpine has already indicated its support for this proposal, and Weinstein said he antic-

ISO-NE News

ipates it will become a co-sponsor as the process moves forward.

Energy Market Advisors

Brian Forshaw of Energy Market Advisors *said* that the rationale for a transition mechanism is "becoming increasingly obvious," as eliminating the MOPR for Forward Capacity Auction 17 makes it difficult to identify solutions that will not distort long-term price signals or could be implemented in that time frame.

According to Forshaw, the goal should be to allow relaxation or elimination of the MOPR while assuring that FCA clearing prices don't collapse below the level of recent capacity auctions.

The most straightforward approach would be suspending the MOPR tariff provisions starting with FCA 17 and implementing a temporary price floor, effective with the suspension of the MOPR. If a more durable solution is not in place after two years, he recommended implementing a net cost of new entry (CONE) adder as proposed by Potomac Economics, the RTO's External Market Monitor, that reflects permanent MOPR elimination and the effects of significant market enhancements.

Forshaw said he would also be willing to consider the Vistra proposal. Still, he would want to explore the potential impact on balancing resources and may need a fallback option at the end of the transition period if a more durable solution is not ready.

Feedback from ISO-NE

ISO-NE offered its *feedback* on the stakeholders' proposals, though none amounted to tantamount support.

On FirstLight's CPP proposal, the RTO outright said it does not support it. CPP create incentives for efficient resources to enter the market under both long and short capacity conditions in a capacity market. Still, the FCA price loses its entry and exit signals. There is also a disincentive to follow the RTO's dispatch in forecasted critical times, impacting real-time price formation.

ISO-NE also does not support the reduction of cycle-time provisions of the FCM rules, as Calpine proposed. Calpine would limit participation in the FCA based on a single, predetermined operating characteristic. According to the RTO, the ability of a resource to contribute toward meeting the loss-of-load criteria is dependent on many factors, not just cycle-time limits such as single-source contingencies and fuel arrangements, among others.

The RTO's initial observations of Vistra's proposal were that such transition mechanisms generally require detailed rules across multiple periods, presenting challenges on an expedited timeline. However, the RTO added that implementation concerns also exist as the conceptual approach would impact many systems.

It had similar concerns with the transition mechanism proposed by Energy Market Advisors, which floated a balancing resource concept. ISO-NE said that such a concept is not feasible for an FCA 17 filing, as many complex rules would need to be defined around the settlement and qualification of those resources. The RTO cannot address complex design elements before the first quarter of 2022 filing with FERC.

ISO-NE did, however, appreciate the resource accreditation aspects of the proposal and said it shares the goal of accurately accounting for contributions toward resource adequacy. ■

ISO-NE News

NEPOOL Participants Committee Briefs

ISO-NE Proposes 5.9% Budget Increase

ISO-NE *presented* its proposed 2022 operating and capital budgets to the NEPOOL Participants Committee last week, with increases to both.

The operating budget of $189.2 million before depreciation represents a 5.9% increase from the 2021 figure. The RTO will add nine full-time-equivalent positions to address the burgeoning workload for integrating clean energy and distributed resources in the market development, transmission planning, power system modeling and legal areas, and cybersecurity and information technology support.

ISO-NE expects its capital budget over the next five years to increase from $28 million to $35 million, including $32 million for 2022. The primary influences of the spending hike are the nGEM platform replacement, cybersecurity, the clean energy transition and reliability improvement projects, as well as IT asset and infrastructure replacement.

Although ISO-NE's spending has never exceeded budget, it might happen in 2022, according to Robert Ludlow, the RTO's chief financial and compliance officer. Situations like funding the next phase of the Pathways to the Future Grid project, constructing models to study extreme weather and contingencies, conducting studies, and integrating clean energy, distributed resources and emerging technologies could trigger more spending.

Other additional spending areas include:

- legal costs;
- federal and state policy directives, including multiple scenarios under the 2050 Transmission Study;
- interest rates on tax-exempt debt, pension and post-retirement benefit plan liability costs, and interest income on settlement float balance; and
- potential impact of workforce disruption because of continued uncertainty in remote versus on-site work.

The New England States Committee on Electricity (NESCOE) also *presented* its proposed budget of $2.49 million for next year, an approximately $57,000 increase over 2021 but below the $2.62 million projected in its five-year *pro forma* budget. NESCOE said the reduction reflected "continued rebalance" of technical and legal spending and declines in travel-related expenses and rent.

The budget timeline includes votes at the PC and the RTO's Board of Directors, before filing with FERC by Oct. 15.

Tropical Storm Henri 'Minimally Impactful'

In his *monthly report* to the PC, ISO-NE COO Vamsi Chadalavada said that Tropical Storm Henri — which made landfall at Westerly, R.I., on Aug. 22 — was "minimally impactful" to the bulk electric system. The RTO, local control centers, and transmission, distribution and generation entities were "well prepared" for the storm. As a result, no significant generation resources tripped.

Chadalavada added that ISO-NE declared an abnormal conditions alert on Aug. 20 and canceled it on Aug. 23. In addition, the RTO required no supplemental commitments before or during the storm as the day-ahead commitments met all expected needs, Chadalavada said.

The original peak load forecast was 17,100 MW at 7 p.m. on Aug. 22, but the actual was 16,440 MW for that hour. ISO-NE lost minimal load, with approximately 140,000 customer outages at the peak of the storm, mainly in Rhode Island. Two 115-kV transmission lines were also impacted during the storm, though Chadalavada said both were restored on the same day.

Energy Market Value Rises

In the opening portion of Chadalavada's report, he noted that ISO-NE's energy market value for last month was $534 million (through Aug. 25), up $71 million from the updated July valuation and $229 million higher than the same month in 2020.

Natural gas prices were 22% higher than in July. Average real-time hub LMPs were 37% higher at $48.83/MWh. Average natural gas prices and real-time hub LMPs were up 161% and 105%, respectively.

Daily uplift or net commitment period compensation (NCPC) payments totaled $2.3 million over the period, down $500,000 from the adjusted July value and $1.1 million less than in August 2020. NCPC payments were 0.4% of the energy market value.

Chadalavada said seven new projects totaling 951 MW applied for an interconnection study: two offshore wind, two solar, two solar with batteries and one battery. ISO-NE is currently tracking 296 generation projects, which total approximately 32,631 MW. ■

— Jason York

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

MISO News

MISO Says Dicey Fall Operations Ahead

By Amanda Durish Cook

Normal fall conditions could beget an emergency declaration in September or October, MISO said in a seasonal outlook released Thursday.

The RTO also said excessive generation outages and high loads in autumn could exhaust every megawatt of its capacity and leave staff counting on non-firm imports to maintain system reliability.

Speaking during a Market Subcommittee teleconference, MISO Resource Adequacy Engineer Eric Rodriguez said this fall is projected to have "substantial risk," particularly if there is an active shoulder maintenance season.

"Generation outages on monthly peak remain high during the fall, particularly in October and November," Rodriguez said, referring to historical data. Last October, planned and forced outages on peak crept to more than 50 GW, a five-year high.

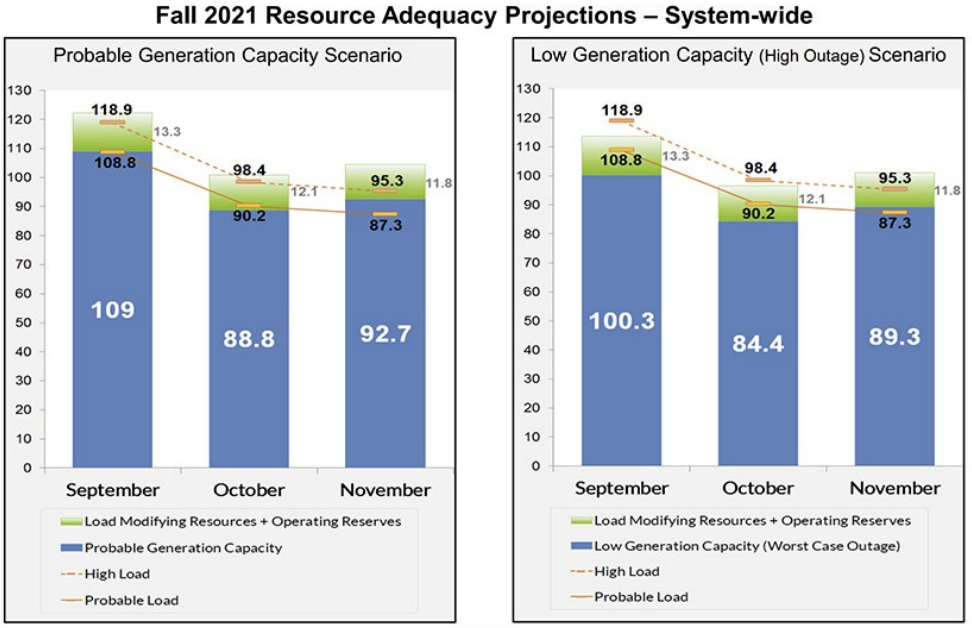
If outages are controlled and load doesn't spike, staff said they could have at least November in hand this year.

Using probable peak forecasts provided by its market participants, MISO *said* it would be left with 108.8 GW of non-emergency resources to cover a 109-GW September peak; 88.8 GW in in non-emergency capacity that would fall short of a 90.2-GW October peak; but 92.7 GW of non-emergency capacity to cover November's projected 87.3-GW peak.

Those totals don't account for 12 GW of load-modifying resources and operating reserves, which are only available for use once MISO declares an emergency. The grid operator said there's a chance it could deplete all emergency resources in September and October and come up short if it encounters a double whammy of unusually high generation outages and load.

However, Rodriguez said MISO can maintain system reliability with wind generation that comes in higher than its accredited value. He also said non-firm imports could help meet demand. The RTO has previously dodged emergency declarations through neighboring imports, thanks to its Middle America footprint.

The National Oceanic and Atmospheric Administration anticipates average temperatures and precipitation throughout MISO's region



Fall high and low capacity projects under both normal load conditions and high outages | *MISO*

this autumn. Its 115-GW all-time fall peak occurred in September 2017, when unseasonably hot temperatures prompted a maximum generation declaration.

The grid operator's late summer has been a whirlwind of two sustained northern heatwaves, back-to-back conservative operations declarations, and record-breaking hurricane destruction in Louisiana. (See *Entergy Re-energizes Small Portion of New Orleans*.)

However, the summer's only maximum generation event occurred in early June when a heat wave struck the northern footprint.

June Pricing Evaluation

MISO revisited its June 10 emergency declaration in its North and Central regions after some market participants criticized its decision not to use some offered emergency resources. (See "MISO Defends June Emergency Declaration," *MISO Market Subcommittee Briefs: July 8, 2021*.)

Economic, non-firm imports responded to pricing signals during the emergency, making some members' emergency offers unnecessary and boosting imports' prices between MISO's ex-ante and ex-post pricing calculations. Emergency resources do not participate in the RTO's pricing.

"It's the inflexibility of some of these out-of-market, emergency resources that drives this," Kevin Vannoy, MISO's director of market design, said. "When it comes to emergency-type conditions, MISO is in the position where a lot of its capacity supply stack are inflexible, emergency-only, out-of-market resources."

Vannoy pointed out that MISO has emergency offer floors, not emergency price floors, and makes no guarantee of prices.

Staff said they only use emergency offers when its economic supply, including non-firm imports, is exhausted.

Vannoy said imports provide "more flexible and more economic" resources. He said if emergency-only resources want more certainty in pricing, they should register as market assets.

"We can and probably will see this in the future," he said, predicting imports will supplant the need for MISO's slowest emergency resources.

ITC Holdings' Marguerite Wagner said the emergency scenario raises the question of whether slow-moving emergency resources should be able to clear MISO's capacity auction.

Shawn McFarlane, the grid operator's executive director of market operations, said staff will hold more stakeholder discussions on the topic during upcoming Market Subcommittee meetings. ■

MISO News

Entergy Touts Restoration as NOLA Leaders Question Lack of Blackstart Service

Continued from page 1

an "unprecedented level of destruction and devastation."

"The damage in terms of pole counts is worse than Hurricane Katrina, Delta and Zeta combined," said John Hawkins, vice president of distribution operations for Entergy Louisiana.

Hawkins said crews found damage beyond what was expected in some areas.

"Changing estimated restoration dates can and will happen in almost any restoration," he added.

But Hawkins said some of Entergy's restoration was completed earlier than originally anticipated, in the case of most of Baton Rouge, which was returned to service by Sept. 5, ahead of Entergy's original Sept. 8 estimate. He said connecting Baton Rouge earlier than expected frees up crews to descend upon rural spots and areas that were initially inaccessible after the hurricane.

"But I'm going to have to temper this good news," Hawkins said, noting a tropical *depression* in the Gulf that has a slight chance of striking Louisiana this week.

"Unfortunately, it could bring rain to our already saturated area" and slow restoration work, he said.

Hurricane Ida destruction in Grand Isle, La. | *Entergy*

"This is a good day," Entergy New Orleans CEO Deanna Rodriguez said, emphasizing that Entergy was able to restore nearly 70% of the 205,000 New Orleans customers without power within a week.

"I'm going to repeat that because it's so monumental," she said. "I think it's near-miraculous the speed at which we've been able to return customers."

Rodriguez said nearly 90% of greater New Orleans should have lights by Sept. 8. She said Entergy will prioritize supply to pharmacies, banks, gas stations and grocery stores so more residents can return.

May said Entergy was able to restore key pumping stations for crude oil refineries along the coast. He declined to identify any stations that were restored.

May also announced an open-ended pause on late fees and shutoffs for all Louisiana customers

"We're proud of what we've accomplished," he said. "But we have a long way to go."

Some 21,000 utility workers are helping to restore power in Louisiana in the wake of Hurricane Ida. | *Entergy*

Raised Eyebrows over Blackstart Decisions

As more of Louisiana is lit, New Orleans leadership is questioning why Entergy didn't tap the New Orleans Power Station to switch on a portion of New Orleans in Ida's immediate aftermath.

May, on a Sept. 2 media *call*, insisted the power station "absolutely" has the ability to blackstart, but said it was not the "preferred path" in this case.

May said a nearly three-day wait to connect the power plant to a line from nearby Slidell in Cleco territory allowed the utility to use

MISO News

the plant as a "shock absorber" and restore New Orleans in "a more controlled and more robust way." (See *Entergy Energizes Second Tx Line, Generator*.)

"It is not a question of whether it can or cannot. It absolutely can," May said of the decision not to activate blackstart service. "The best way of assuring we can rapidly bring up power in the greater New Orleans region is the path we chose with a source out to the east."

Entergy said it was "fully prepared" to generate within the islanded city but said "having the tie to the rest of the power grid provides a more stable and resilient supply to customers and allows us to bring in power from other sources." It *insisted* the plant was functioning as designed.

However, New Orleans City Council President Helena Moreno said ratepayers who are paying for the plant "deserve answers." She promised a "deep dive" into why the plant was not started without assistance from the MISO system.

Entergy executives repeatedly told the council that the plant could not start without connecting to the larger grid after the storm, Moreno said in a Facebook *post*.

"That's contrary to all the testimony the previous council received when it approved the plant in 2018," she wrote.

Entergy New Orleans ratepayers funded the New Orleans Power Station's construction through an additional $11/month fee on their bills.

Four years ago, former Entergy CEO Charles Rice said in written testimony that the plant would "include black-start capability, which will enable the company to start the unit even when there is no power on the electric grid."

"This will give the company the ability to restore electric service, should a complete loss of service occur. This could be a tremendous benefit if New Orleans is electrically 'islanded' from the rest of the interconnected transmission grid, as it was after Hurricane Gustav," Rice said.

Hurricane Gustav in 2008 islanded the New Orleans-Baton Rouge from the grid for more than 33 hours when 14 transmission circuits tripped offline, requiring resynchronization.

Entergy also told the council in filings that the plant's blackstart feature would be "critically important" given the area's risk for extreme weather and that its "close electrical proximity to electric demand" could keep voltage and frequency in check during restoration activities.

The New Orleans Power Station can supply only about 10% of New Orleans' more than 1 GW needs. ■

Entergy's fallen transmission tower shows considerable rust. | *WWL-TV*

NYISO News

NYISO Stakeholders Discuss Resource Adequacy, Capacity Rules

By Michael Kuser

Stakeholders on Aug. 30 discussed the methodology behind *NYISO*'s straw *proposal* on capacity accreditation as the grid and energy market adapt to an increasingly diverse resource mix.

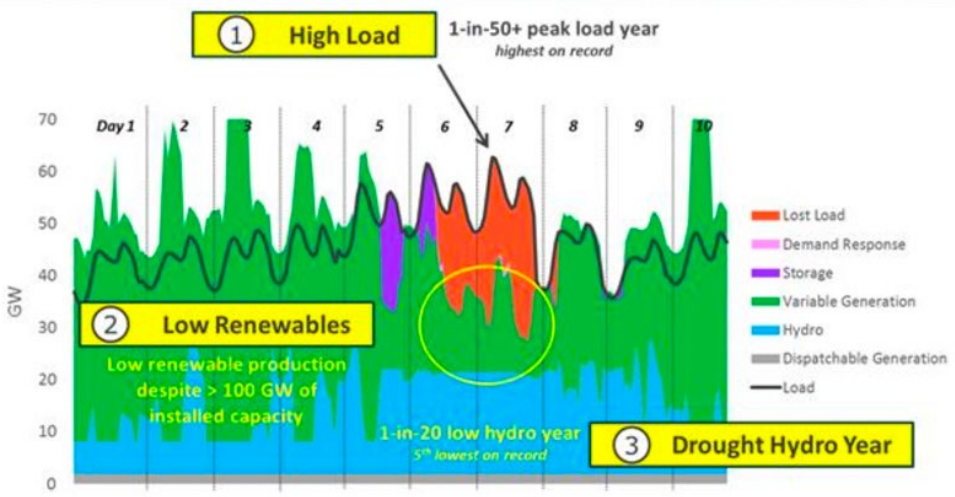
The Installed Capacity/Market Issues Working Group spent nearly four hours discussing a *study* on Effective Load Carrying Capability (ELCC) by San Francisco-based consultancy Energy and Environmental Economics (E3).

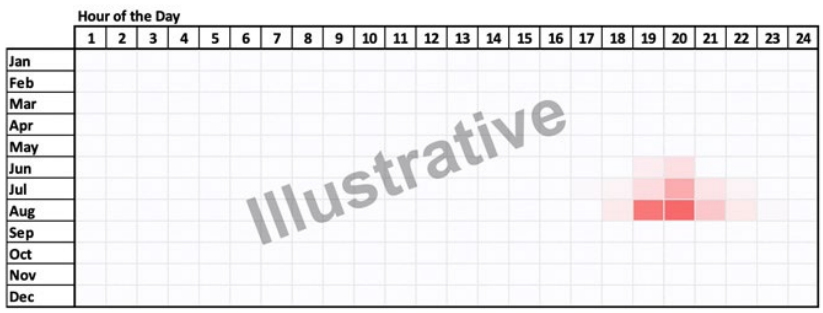
"When we really were building up our resource adequacy capabilities it was a bit of a backwater… not many people knew what loss of load probability [LOLP] was and why most utilities do it," said E3 senior partner Arne Olson. "But now after what we saw in Texas, I think we've seen that even these kinds of extreme events can really happen." (See *'Best Market in the World' Faces Uncertain Future*.)

Grid planning was relatively straightforward when RTOs only had to add up nameplate capacity to gauge resource adequacy, but now they must consider how the system as a whole is performing and all the interaction among solar, wind, batteries and hydro, Olson said.

"The total amount of effective capacity we have is a complex function of all of the individual generators and all of the ways that they interact throughout the year and during the hours when we might have a loss-of-load event," Olson said. "So that's why we have to use a technique like ELCC; it's a way to help us deal with the changing resource mix."

The firm last year co-authored a Net Zero New England study for Calpine and has been advising *PJM* on their capacity accreditation.





As renewable penetration grows, planning problems shift from traditional need to meet peak demand hours (e.g., summer) to new questions of meeting net demand (e.g., over multi day low renewable events). | *E3*

FERC rejected PJM's proposed ELCC revisions in April, but on June 30 accepted a revised proposal minus the "transition mechanism" that the commission had found unjust and unreasonable. On the same day, PJM proposed a replacement for its extended minimum offer price rule (MOPR-Ex) as a tool for buyer-side mitigation (BSM). (See *Mixed Stakeholder Reception to PJM MOPR Replacement*.)

Modeling Basics

ELCC represents a percentage of the "perfect" capacity that a resource provides in meeting a target reliability metric (for example, 0.1 day/year loss of load expectation) and can also be thought of as the incremental load that can be met by an incremental resource throughout the year while maintaining the same target reliability metric.

"A lot of the dynamics that we tried to illustrate here are simplifications of what's actually happening on the system," said E3 Director Zach Ming. "The reality is, there is no difference between the diversity benefit or penalty and diminishing returns. Those are the exact same thing."

Resources that are similar to each other have a negative diversity benefit, which creates the diminishing return, and resources that are different from one another interact positively with each other, he said.

The ISO's Market Monitor, Potomac Economics, presented a *paper* supporting the study's recommendation to calculate ELCC using a marginal approach. That approach entails using a reliability value of the next incremental supply of a resource type — or combination of resources — measured relative to an existing portfolio of resources, rather than taking the average value of the existing supply of the resource type.

With so many different types of capacity with different availability, it's useful to have a concept that represents something they all can be compared to, but every type of capacity, including 'perfect' capacity, has diminishing returns, said Pallas LeeVanSchaick of Potomac Economics.

"E3 is highlighting that some of the resources have diminishing returns that diminish faster than perfect capacity, so they use perfect capacity as a benchmark for quantifying the diminishing returns of other resources," LeeVanSchaick said.

NYISO News

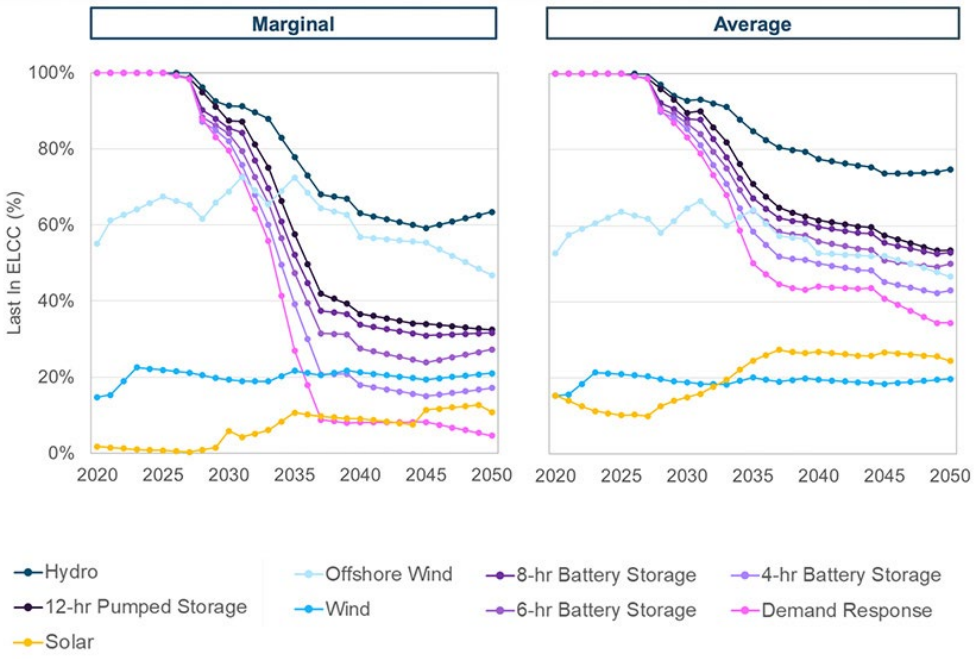
Pairing Logic

Several stakeholders expressed concern about pairing the ISO's efforts on capacity accreditation with buyer-side mitigation, the latter of which they believed could be handled relatively quickly. Tying the two together risks having FERC reject the BSM straw proposal because the commission has accepted ELCC proposals from three other RTOs/ISOs based on the average method of calculation rather than the marginal one.

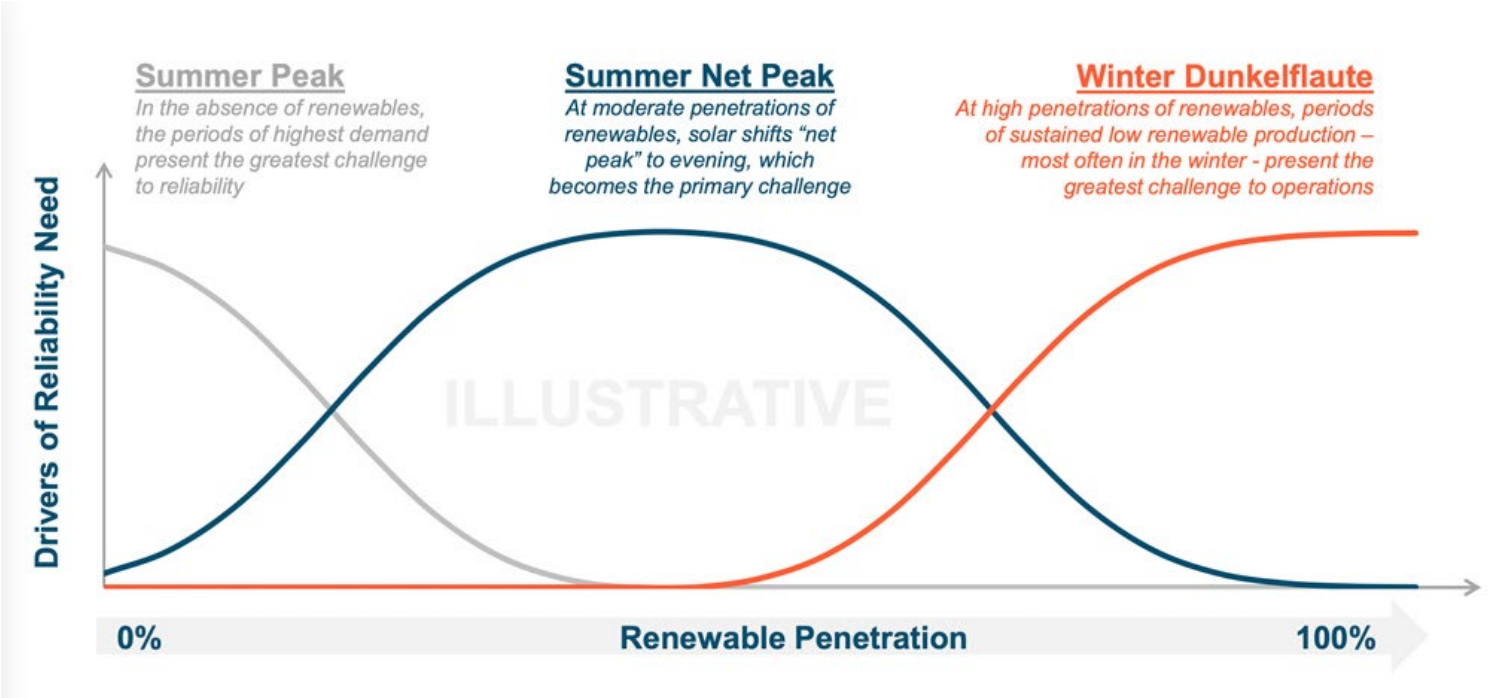
"We do think that this effort is highly linked to our success with the buyer-side mitigation rule changes, and, in fact, we think there's some tariff language that we absolutely need to modify if not replace and, in its place, put these rules that we're talking about," NYISO Director of Market Design Michael DeSocio said. "To the extent we have all of the rules figured out, we would do that, though I don't think we will have them figured out because we are trying to move [BSM] forward as quickly as we can."

DeSocio presented an *overview* of the PJM MOPR filing and said NYISO has been clear in its reasoning for a case supporting just and reasonable outcomes in the capacity market with large modifications to BSM.

"We do need it demonstrated that the capacity market remains competitive ... and [an ELCC approach to capacity accreditation] is a large part of helping us to do that," he said. "Separating them we don't think is workable; in fact, we think it'll be important to be very clear on how we intend at the highest level to treat capacity accreditation going forward so that we can properly perform those analyses and present that information as part of a whole framework." ■



Illustrative results showing marginal ELCC vs average method ELCC | *E3*



Timing Shift: Increasing levels of renewables will cause the timing of reliability challenges to shift to different times of day – and eventually to different times of year. | *E3*

PJM News

Pa. RGGI Regulations Approved by IRRC

By Michael Yoder

Pennsylvania is one step closer to joining the Regional Greenhouse Gas Initiative (RGGI) after a key agency on Wednesday approved regulations for the carbon budget trading program that would limit emissions from the state's power sector.

In a 3-2 party-line vote, the Pennsylvania Independent Regulatory Review Commission (IRRC) approved the 84-page *program* presented by the Department of Environmental Protection (DEP) providing provisions for the state to enter RGGI. The state's Environmental Quality Board (EQB) voted 15-4 in July to back the rules. (See *PA Backs Final Rule for RGGI Entrance*.)

The Pennsylvania Office of Attorney General now has 30 days to review the legality of the IRRC's regulations, while the General Assembly has been adopting resolutions to oppose the regulations. (See *Pa. Senate Committee Disapproves of RGGI Entry Again*.)

IRRC Chair George Bedwick issued the deciding vote to approve the regulations, saying he understood whatever decision the commission would make will receive criticism. Bedwick said each commissioner is meant to be independent in their thinking and their vote on issues.

"What I hope we can all agree on is that we have made every effort to approach the issue with an open mind, and we have in fact conducted this proceeding in an open and fair manner in permitting as much testimony as people wanted to provide us with," Bedwick said.

The chairman said he was persuaded that Pennsylvania's Air Pollution Control Act granted the DEP to issue the rulemaking, saying the law provided "broad" authority to adopt rules and regulations to prevent, control and reduce air pollution and to establish fees supporting air pollution controls. He said he examined the intent of the legislation when it was first passed in the 1960s. "Viewing the broad scope of the delegation, I tend to believe they wanted to regulate whatever in the future was determined to be a pollutant."

Commissioner Murray Ufberg, who also voted in favor, said he was influenced by the "specificity of the analysis" conducted by the DEP. Ufberg said he is concerned about the air quality in Pennsylvania and the amount of CO_2 generated by the state, saying he was "shocked" when he learned the totals.

Members of the Pennsylvania DEP answer questions during Wednesday's meeting of the Pa. IRRC. | *Pa. IRRC*

Ufberg said it's "apparent" that more efforts need to be done to mitigate air pollution in Pennsylvania, and the new regulations would go toward cleaning the environment. He said his decision was also influenced by his childhood growing up in a coal community in the state, saying he has seen the "resiliency" of people in those towns who are willing to do what they need for their families, including retraining in new industries.

"I must be optimistic, as we all should be, that alternative energy opportunities will offset and hopefully greatly exceed the adversity of those losses," Ufberg said. "Without hope, we're all in big trouble."

Vice Chair John Mizner voted against the regulations, saying the issue before the commission was not the need to protect the environment, but the manner in which action is taken. Mizner said the process of drafting the regulations was "flawed," partially because of COVID-19 pandemic protocols that limited in-person hearings on the regulations.

He also said cited a lack of engagement by Gov. Tom Wolf's administration with the General Assembly over the regulations and argued that the impact of the policy on the state warranted legislative review.

"The regulatory process should be a collaborative process," Mizner said. "I don't believe for this regulation that there's been sufficient access to the process that I think such a regulation deserves."

In-person Comments

Dozens of legislators, environmental and economic advisers, trade unions and interested community members made comments to the commission for nearly six hours Wednesday before its vote, laying out both the pros and cons of the program.

Sen. Carolyn Comitta | *Pa. IRRC*

Sen. Carolyn Comitta (D), minority chair of the Environmental Resources and Energy Committee, said the natural resources of Pennsylvania are the "common property of all the people, including generations yet to come." Joining RGGI is a step to ensure the environment is secure, she said.

PJM News

Sen. Joe Pittman | *Pa. IRRC*

Sen. Joe Pittman (R), vice chair of the committee and one of the most outspoken legislators opposing RGGI, said the rule was "very personal and very emotional" because of the impact it will have on his constituents. Pittman said more than 6,000 MW of carbon-emitting electricity is generated in his district, and that energy is set to disappear by entering RGGI.

Pittman said the intent of the rule is to tax the emitting of carbon from power plants and redistribute the money for other purposes, a power that only lies with the legislature. He also said Pennsylvania will be the only state in RGGI to enter the compact without the approval of the legislature.

Pittman said he attempted many times to engage the Wolf administration on the impacts of the program on the communities of his constituents after the governor signed his executive order, but he received no response. (See *Pennsylvania Governor Signs RGGI Executive Order*.)

"From where I sit as an elected member of the Pennsylvania Senate, I can assure you I do not see a weighted benefit versus the enormous costs the constituents I represent will bear," Pittman said.

Rep. Pam Snyder | *Pa. IRRC*

One of the most impassioned speakers against the rulemaking was Rep. Pam Snyder (D), who represents parts of western Pennsylvania. Snyder said in her home of Green County, the coal industry makes up four of its top five employers.

Snyder called RGGI an "unfair tax on the fossil fuel industry" that will not impact the effects of climate change on the state. She said RGGI will "artificially and prematurely" shut down coal-fired power plants in the state, impacting energy generation.

"Make no mistake about it, Pennsylvania's energy grid is not prepared to operate without coal," Snyder said. "When it's 100 degrees and air conditioners are running 24/7, it's coal that gets called upon to supply the energy needed."

Outside Responses

Following the commission's vote, Mark Szybist, senior attorney for the Climate and Clean Energy Program at the Natural Resources Defense Council, said it represented the "most important climate action that Pennsylvania has taken in more than a decade." Szybist said the DEP will now have the ability to move forward with integrating the state into RGGI, but he warned about "hurdles from bad apples" in the legislature.

"Pennsylvanians don't want their legislators to tie RGGI up with red tape but instead demand an equitable clean energy economy that will bring shared prosperity," Szybist said.

Analysts from ClearView Energy Partners said Pennsylvania is now poised to be the largest RGGI member state by electric sector CO_2 emissions, generation and consumption. The analysts said Pennsylvania's entrance into RGGI "could further push the clearing price for emissions allowances in RGGI above their record highs."

ClearView also said several risks still exist for Pennsylvania's RGGI entrance, including the passage of a bill that would invalidate the DEP's rulemaking (*SB 119*), potential legal challenges and the term limit of Gov. Wolf, who will leave office in January 2023.

"If a GOP candidate succeeds him, a new Republican governor would almost surely oppose participation in RGGI and would be more inclined to sign legislation undoing the rule," ClearView said. ■

Commissioners of the Pennsylvania Independent Regulatory Review Commission meet to discuss regulations regarding the Regional Greenhouse Gas Initiative (RGGI). | *Pa. IRRC*

PJM News

Ohio Senate Challenges PJM's MOPR-Ex Filing

By Michael Yoder

Members of the Ohio legislature are challenging PJM's proposed replacement for the extended minimum offer price rule (MOPR-Ex), asking FERC to reject the RTO's July filing.

Sen. Matt Huffman | Ohio General Assembly

In comments sent last week to the commission, Ohio Senate President Matt Huffman (R) and Sen. Rob McColley (R), majority whip and chairman of the Energy and Public Utilities Committee, requested that the PJM proposal endorsed at a special Members Committee meeting on June 30 and approved by the Board of Managers on July 7 be rejected (ER21-2582). (See PJM Board Approves MOPR Rollback.)

The senators said that PJM's MOPR-Ex filing would "severely undermine Ohio's efforts to promote robust and fairly administered competitive electricity markets in our state."

"PJM's new construct would freely allow states outside of Ohio to effectively export their policies to our state," the senators said. "FERC must stand up to this overreach and discriminatory construct by rejecting the filing."

PJM said its MOPR proposal would "maximiz[e] transparency and market confidence" through identification of buyer-side market power (BSMP). Market participants would be asked to sign attestations declaring they are not exercising market power or receiving state funds tied to clearing in the capacity auction. PJM and the Independent Market Monitor would conduct "fact-specific, case-by-case reviews" if market power is suspected. Referrals of BSMP would then be made to the commission for a final determination.

The comments from the Ohio legislators come on the heels of more than two dozen comments that came into the commission late last month as PJM stakeholders issued a mix of support and opposition to the RTO's filing. (See Mixed Stakeholder Reception to PJM MOPR Replacement.)

PJM adopted the extended MOPR in response to FERC's 2-1 ruling in December 2019 saying MOPR should apply to all new state-subsidized resources to combat price suppression in the capacity market. Then-Chair Neil Chatterjee and fellow Republican Bernard McNamee formed the majority, with Democrat Richard Glick angrily dissenting, calling it an attack on state decarbonization efforts. Glick asked PJM to undo the rule after he was named chairman by President Biden in January.

Ohio Statehouse in Columbus | MJ, CC BY-SA 4.0, via Wikimedia Commons

Disparate State RPS Policies

While several states in PJM's 13-state footprint have enacted increasingly ambitious renewable energy targets in recent years, Ohio's Republican-controlled government has not joined the trend.

In 2019, Gov. Mike DeWine (R) signed House Bill 6, which reduced the state's renewable portfolio standard from 12.5% by 2027 to 8.5% by 2026, after which the RPS would be eliminated. Last month, DeWine signed a bill giving county governments the power to review and reject utility-scale wind and solar projects before developers can apply to the state Power Siting Board. (See Ohio Governor Signs Bill to Block Renewables.)

Sen. Rob McColley | Ohio General Assembly

Huffman and McColley said PJM's MOPR filing "represents a significant step backward for an RTO that has traditionally been a champion of just and reasonable competitive markets." They said utilities in Ohio originally joined PJM expecting to participate in a regional market "in which reliability would be ensured by competitive resources vying to serve load at the lost cost."

"Ohio desires a market based on competition, not subsidies, and FERC has a duty to protect that market from the disruptive actions of a one state that impact the outcomes for other states," the senators said in their letter.

Senate Resolution

Sen. Mark Romanchuk | Ohio General Assembly

Huffman and McColley said the Ohio Senate will "shortly" consider a concurrent resolution by Ohio Sen. Mark Romanchuk (R) to "urge the preservation of the minimum offer price rule for the PJM capacity market." The resolution calls on PJM and FERC to "evaluate whether state-subsidized generation resources have a material impact on price formation in PJM's capacity market."

Citing "billions of dollars of investment in new generation resources in Ohio since deregulation began in 1999," the resolution said the state has rejected subsidizing generation resources "in favor of encouraging competition."

"The elimination of the minimum offer price rule would increase the risk of a critical reliability problem within the PJM states and would force Ohioans to bear costs associated with other states' generation resource preferences," the resolution said.

Huffman and McColley said the full Ohio Senate will be "shortly" considering the resolution. Besides the resolution, the senators said the general assembly also intends to hold its own hearings on the MOPR and to "explore how to maintain Ohio's commitment to competitive markets in the face of a PJM filing that is clearly antithetical to that cause." ■

PJM News

PJM PC/TEAC Briefs

Planning Committee

2021 IRM Results

PJM is recommending an installed reserve margin (IRM) of 14.6%, slightly up from 14.4% required in 2020.

Patricio Rocha Garrido, PJM | © RTO Insider LLC

During the Aug. 31 Planning Committee meeting, Patricio Rocha Garrido of PJM's resource adequacy department *reviewed* the 2021 reserve requirement study (RRS) results, which determine the RTO's IRM and forecast pool requirement (FPR) for 2022/23 through 2024/25 and establish the initial IRM and FPR for 2025/26. The results are based on the 2021 capacity model, load model and capacity benefit of ties (CBOT).

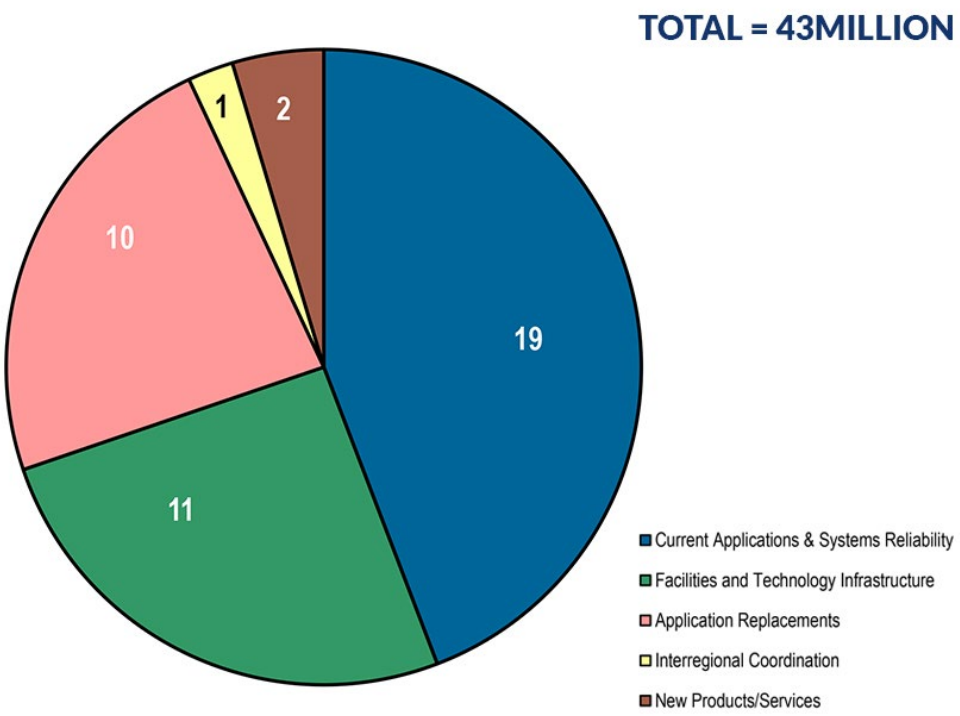
Rocha Garrido said the recommended FPR for 2021 slightly increased to 1.0887, from 1.0865 for 2020. He said the FPR is the most important parameter of the study because it is used in the reliability requirement calculation for Reliability Pricing Model (RPM) auctions.

The 2021 capacity model is driving the increase in both the FPR and the IRM, Rocha Garrido said, with the average effective equivalent demand forced outage rate (EEFORd) of 5.8%, compared to 5.78% in the 2020 RRS. Rocha Garrido said the higher average EEFORd was caused by the increase in the average unit size, going to 175 MW in the 2021 RRS compared to 159 MW in 2020.

"We're spreading the risk across a smaller quantity of units, which in general tends to be bad for reliability," Rocha Garrido said.

The CBOT — the help PJM can expect from imports during peak loads — is also estimated to increase pressure on the FPR and IRM. Rocha Garrido said imports from neighboring grid operators have decreased from 1.54% in 2020 to 1.47% in 2021.

Rocha Garrido said the 2021 load model is putting downward pressure on both the FPR and the IRM because PJM is "seeing a slight reduction in the standard deviation of the summer peak week" compared to 2020. The *2021 PJM Load Forecast Report*, which was used in the study, was released by the RTO in January.



PJM's preliminary 2022 capital budget | *PJM*

Rocha Garrido said the study results will also be used in the 2022/23, 2023/24 and 2024/25 Base Residual Auctions (BRAs). He said delays in the 2019 BRA for 2022/23 necessitated the use of data from the 2020 study.

The PJM and world load models used are based on the 2001-2013 period and were approved at the Aug. 10 PC meeting. (See *Stakeholders Endorse but Question PJM's Load Model*.) The 2021 RRS *assumptions* endorsed at the June PC meeting were also used. (See "2021 RRS Assumptions Endorsed," *PJM PC/TEAC Briefs: June 8, 2021*.)

The PC will vote on the study results at its next meeting, with final votes at the Markets and Reliability Committee and Members Committee meetings in November.

Paul Sotkiewicz of E-Cubed Policy Associates asked what was driving the average unit size increase.

Rocha Garrido said it mainly from the fact that PJM is not modeling effective load-carrying capability (ELCC) resources in the RRS anymore. He said units like landfills, dispatchable hydro, wind and solar have been left out.

Sotkiewicz said "we're entering pretty uncharted territory," as the previous RRS results included ELCC resources. He asked if those resources are being taken out of the capacity model and being treated as if they "have no contribution whatsoever."

"I'm trying to figure out where the ELCC piece fits into this," Sotkiewicz said.

Rocha Garrido said dealing with ELCC is a "tricky topic" because past modeling of unit size was "imperfect" when they were included. But he said having the model with or without ELCC resources should not impact the FPR.

Manual 14G Updates Endorsed

Stakeholders unanimously endorsed updates to Manual 14G regarding the behind-the-meter generation (BTMG) business rules on status changes.

Terri Esterly, PJM | © RTO Insider LLC

Terri Esterly, senior lead engineer for PJM's markets automation and quality assurance department, *reviewed* the *revisions* to Manual 14G: Generation Inter-

PJM News

connection Requests. The revisions were first presented at the Aug. 10 PC meeting, and no language changes were made between the meetings. (See "Manual 14G First Read," *PJM PC/TEAC Briefs: Aug. 10, 2021*.)

The manual updates resulted from work conducted at special sessions of the Market Implementation Committee, Esterly said, where stakeholders reviewed existing BTMG business rules and identified gaps in the rules. Related changes to Manual 14D were presented at the August Operating Committee meeting and are set to be voted on at the committee's meeting Friday. (See "Manual 14D Updates," *PJM Operating Committee Briefs: Aug. 12, 2021*.)

Esterly said the updates included language on megawatts changing from BTMG status, where they can net against the load, to the PJM market resource status. Esterly said the updates were designed to address conflicts with the RPM must-offer requirement and removal from generation capacity resource status business rules, as well as clarifying and "adequately" documenting all the processes related to status changes.

Most of the Manual 14G updates were in section 1.6.1, Esterly said, clarifying information required in an interconnection request to designate capability as a generation capacity or energy resource and to "ensure consistency" with the BTMG definition already in the tariff. The updated language includes a list of information required in a new services request for a BTMG unit, a definition of behind-the-meter load and a clarification on how to determine the maximum host/process loads.

The manual updates will now go to the Sept. 29 MRC meeting for a first read and endorsement in October.

Preliminary 2022 Capital Budget

Jim Snow of PJM reviewed the RTO's preliminary 2022 capital budget, which is set at $43 million, an increase of $3 million compared to the 2021 budget. Snow said PJM is anticipating spending $45 million per year over the next five years in the capital investments.

Snow said the $3 million increase from the previous budget is primarily being driven by cybersecurity and data analytic costs.

The largest piece is $19 million for current applications and systems reliability, a $4 million increase over 2021. Snow said the money will be used for enhancing the abilities of applications PJM currently uses, including cybersecurity tools, dispatch tools and system planning.

Facilities and technology infrastructure is the second biggest piece of the budget at $11 million. Snow said the budgeted money includes the purchase of network, server and storage infrastructure equipment; upgrades to physical and virtual equipment to allow essential operations on-site and working from home because of the COVID-19 pandemic; and equipment upgrades for cybersecurity monitoring.

Application replacements are budgeted at $10 million and include the Next Generation Markets Systems (*nGEM*), a multiyear partnership between PJM, MISO, ISO-NE and General Electric to transform the market systems architecture, technology and products.

The Finance Committee will develop a recommendation letter at its Sept. 13 meeting to send to the PJM Board of Managers, and the board will consider the budget at its meeting on Sept. 22.

Transmission Expansion Advisory Committee

Generation Deactivation Notification

Phil Yum of PJM *provided* an update on 14 recent generation deactivation notifications totaling nearly 8,000 MW at the Aug. 31 Transmission Expansion Advisory Committee meeting.

Houston-based GenOn Holdings requested the April 1, 2022, deactivation of the 627-MW coal-fired Avon Lake 9 Generating Station and 21-MW oil-fired Avon Lake 10 unit, both located in Ohio's American Transmission Systems Inc. (ATSI) transmission zone, and the 568-MW coal-fired Cheswick Generating Station in the Duquesne transmission zone in Pennsylvania. GenOn originally requested a deactivation date of Sept. 15 for the three units.

GenOn also requested the May 31, 2022, deactivation of 1,233 MW from the coal-fired Morgantown Generating Station 1 and 2, located in the PEPCO transmission zone in Maryland.

Exelon requested that its two Byron nuclear units, both in the ComEd transmission zone in Illinois, be deactivated Sept. 14 and 16. The company originally announced in 2019 its intention to retire the units. The Illinois legislature is still working on an energy bill that would potentially provide $700 million to bail out Exelon's three nuclear plants in the state. (See *Massive Ill. Energy Bill with Funding for Exelon's Nukes Still Stuck*.)

NRG Energy has requested that the coal-fired Waukegan Generating Station Units 7 and 8 and the 510-MW coal-fired Will County Generating Station Unit 4, all located in the ComEd zone, be deactivated on May 31, 2022.

Yum said PJM completed reliability analyses for these requests and determined the units can retire as scheduled.

NRG also requested a May 31, 2022, deactivation of its coal-fired 412-MW Indian River 4 Generating Station, but the reliability analysis identified the need to keep the plant operating. Yum said PJM identified seven different thermal violations, estimated to cost $117.4 million. PJM and NRG are still working on solutions to allow for deactivation.

PJM also received generation deactivation notices for three additional units for May 31, 2022, including Talen Energy's 115-MW gas- and oil-fired Pedricktown Power Plant in the Atlantic City Electric transmission zone and the 120-MW Newark Bay Power Plant in the Public Service Enterprise Group transmission zone, as well as Vistra's 1,320-MW coal-fired William H. Zimmer Power Plant in the Duke Ohio/Kentucky transmission zone. Yum said a reliability analyses were completed for each unit, and they can retire as scheduled.

A total of 7,918 MW of generation is set to be deactivated between the 14 units. ■

— Michael Yoder

2021 RRS Study results:

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR*
2021	2022 / 2023	14.92%	**14.9%**	5.07%	**1.0907**
2021	2023 / 2024	14.74%	**14.7%**	5.02%	**1.0894**
2021	2024 / 2025	14.67%	**14.7%**	5.01%	**1.0895**
2021	2025 / 2026	14.64%	**14.6%**	5.00%	**1.0887**

PJM's 2021 reserve requirement study (RRS) results versus its 2020 RRS results | *PJM*

Company Briefs

Entergy Texas CEO Announces Retirement

Entergy Texas, Inc.

Entergy Texas President and CEO Sallie Rainer announced last week that she will retire on Nov. 14, ending a nine-year tenure.

Rainer joined Entergy in 1984 in the generation planning department working in various long-term planning roles. In 1997, she joined the energy management organization in The Woodlands, and in 2005 she was named director of regulatory affairs and energy settlements.

Rainer's role will be filled by Eliecer Viamontes, the current vice president of utility distribution operations.

More: *Beaumont Enterprise*

Mossad's Former Chief Now Head of Doral LLC

Yossi Cohen, the former chief of the Israeli intelligence agency Mossad, has been named director at Doral Renewables LLC, the U.S. subsidiary of the Israel-based Doral Group.

A company statement said Cohen "will strengthen the company's management team and will take an active part in promoting the company's goals across multiple initiatives."

More: *Renewables Now*

Otter Tail Power to Sell Stake in North Dakota Coal Plant

Otter Tail Power Company

Otter Tail Power last week said it plans to sell its 35% stake in the Coyote Station Power Plant in North Dakota by 2028, according to documents filed with the Minnesota Public Utilities Commission.

The utility, which plans to end its investment in the plant as part of its push to add more renewable energy sources, said "more flexible and economical resource options are available" and that it is concerned its obligation to the plant will become too costly for customers.

More: *The Associated Press*

Vestas Wins 290 MW of Turbine Orders for US Wind Farms

Denmark's Vestas Wind Systems A/S last week announced orders to deliver 56 turbines for 290 MW of wind projects in the U.S.

Vestas will deliver turbines to wind parks in Michigan and Pennsylvania, along with another unspecified project.

The company will begin delivering the turbines in 2022.

More: *Renewables Now*

Federal Briefs

BLM Aims to Cut Costs for Solar, Wind Projects on Public Land

The Interior Department's Bureau of Land Management last week announced it has initiated a process to revise regulations related to renewable energy permitting and rights-of-way on public lands — and to make access to federal lands cheaper.

The process will start with four public listening sessions in September and a separate consultation with Native American tribes. The sessions will focus on rent lease schedules and fees for wind and solar rights-of-way, application processing times and environmental justice considerations.

The renewable industry argues the charges imposed by the Interior Department are out of sync with private land rents, which can be below $100 per acre, and do not come with fees for power produced.

More: *Reuters*

Dems Call on House to Use Spending Plan to Repeal Fossil Fuel Subsidies

A group of more than 50 Democrats last week called on Speaker Nancy Pelosi and House Majority Leader Steny Hoyer to include a repeal of fossil fuel subsidies in the party's multitrillion-dollar infrastructure package.

The group, led by Reps. Carolyn Maloney (D) of New York and Ro Khanna (D) of California, penned a letter to the House leaders asking that the repeal of fossil fuel subsidies be included in Democrats' Build Back Better Act because they do not bolster U.S. energy independence or create new jobs, among other things.

Senate Majority Leader Charles Schumer (D) recently said the infrastructure bill and Democrats' reconciliation spending package would help reduce U.S. carbon emissions by 45% by the end of the decade compared to 2005 levels.

More: *The Hill*

Interior Department Announces Environmental Review of Wind Facility

The Department of the Interior last week announced that the Bureau of Ocean Energy Management plans to conduct an environmental review of a proposed commercial-scale wind project off the coast of New York.

The project proposes to build up to 122 turbines, which would generate 880 to 1,300 MW, to help the state meet its clean energy goal of achieving 70% electricity from renewable sources by 2030. The lease area is in federal waters approximately 31 miles east of Montauk, New York, 19 miles south of Martha's Vineyard, Mass., and 17 miles from Block Island, RI.

More: *Department of the Interior*

State Briefs

CALIFORNIA

LA City Council Votes to Transition to 100% Renewable Energy by 2035

The Los Angeles City Council last week voted 12-0 to have its Department of Water and Power transition to 100% renewable energy by 2035, as well as develop a long-term hiring plan for nearly 10,000 green jobs.

The motion also directs the DWP to report every six months on the transition to renewable energy to the council's Energy, Climate Change, Environmental Justice and River Committee. The transition is expected to create 9,500 jobs and include an investment of between $57 billion and $87 billion.

The 2035 deadline is a decade earlier than the city's previous goal.

More: *CNS*

Lawmakers Pass 'Fix' for Solar Financing

Lawmakers last week passed SB 267 to extend a property tax exemption to solar projects that change ownership and to align the state's tax system to support the mission of federal renewable energy tax credits, which stand at 26% for projects that begin construction in 2021 or 2022.

The bill "applies the exclusion equally to the solar energy system regardless of who owns it, applying equally to both homeowners who install solar energy systems as part of their homes, or for businesses who generate solar energy at larger scales for sale to investor-owned or municipal utilities."

More: *Renewable Energy World*

San Diego County to Join CCA as Alternative to SDG&E

The San Diego County Board of Supervisors voted 3-2 last week to join San Diego Community Power (SDCP) — a community choice aggregation program (CCA) made up of San Diego, Chula Vista, La Mesa, Encinitas and Imperial Beach — to serve as an alternative to San Diego Gas & Electric when it comes to purchasing energy contracts.

The county chose SDCP over the Clean Energy Alliance, which buys power for Del Mar, Solana Beach and Carlsbad.

The county will proceed with signing a joint powers authority agreement with SDCP, which will include language to protect the county's general fund should the CCA run into financial difficulty.

More: *The San Diego Union-Tribune*

ILLINOIS

Senate Passes Clean Energy Proposal

The Senate last week approved a massive clean energy package, which cleared the last major piece of Gov. **J.B. Pritzker's** agenda for a vote in the House.

The proposal aims to get one million electric vehicles on the roads in the next nine years and transition to a 100% clean energy sector by 2050. The plan would shutter private, for-profit coal plants that generate more than 25 MW by 2030 and close down municipally-owned coal and natural gas plants by 2045.

The proposal would raise average residential monthly rates by 3%, commercial rates by 5%, and industrial rates by 7%.

More: *Nextstar*

INDIANA

Michigan City Asks NIPSCO to Remove Coal Ash from Site

The Michigan City Council last week asked NIPSCO to remove all coal ash from the Michigan City Generating Station site when the plant closes before 2029.

The council said removal is preferable to placing a cap on coal ash that has accumulated at the century-old coal-fired plant.

More: *The Northwest Indiana Times*

MICHIGAN

DTE Energy to Spend More Money on Tree Trimming

DTE Energy last week said it will spend $70 million through 2023 on top of $190 million set aside for tree trimming each year.

In a filing with the Public Service Commission, DTE said the extreme summer weather has been "unprecedented and challenging" for customers, with about 25% losing power in the last storm. It asked the PUC to approve its plan no later than October.

More: *The Associated Press*

MINNESOTA

Appeals Court Deals Another Setback to Line 3 Foes

The Court of Appeals last week affirmed a decision by the Pollution Control Agency (PCA) to issue a water quality certification for Enbridge Energy's Line 3 crude oil pipeline.

Under the federal Clean Water Act, the PCA was required to certify whether the project met state and federal clean water standards and concluded it did in November 2020. That certification cleared the way for the U.S. Army Corps of Engineers to issue the remaining permit for the pipeline replacement less than two weeks later. Tribal governments and environmental groups challenged the decision. The appeals court said the challenge was not moot but found that the agency had met its legal requirements.

More: *The Associated Press*

PUC Approves Construction of NextEra Wind Farm

The Public Utilities Commission last week said NextEra Energy Resources can proceed with the construction a 40-turbine wind facility.

The 109-MW Walleye Wind Farm will supply electricity to the Minnesota Municipal Power Agency for 30 years.

More: *Daily Energy Insider*

TEXAS

Griddy Settles Over Energy Bills from Feb. Freeze

Electric utility Griddy Energy reached a settlement with Texas officials over enormous bills its customers received after the deadly February storm and cold spell, the Texas Attorney General's Office an-

nounced last week.

Griddy sold power at wholesale prices plus a $9.99 monthly fee. Its rates skyrocketed during the February freeze when the state grid operators raised wholesale prices to $9,000 per MWh, which led to the state suing the utility after customers received bills totaling thousands of dollars. Griddy filed for bankruptcy and confirmed a liquidation plan that waives claims against customers for charges incurred from Feb. 15 through Feb. 19 while the $9,000 price for wholesale power was in effect. Paxton said his office then entered negotiations toward a settlement.

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