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Executive Director Industry Update –February/March 2021

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Bitter Cold Overwhelms Grid, Leaves Millions In Dark

Edward Klump, Peter Behr and Mike Lee, E&E News reporters February 16, 2021

Bitterly cold temperatures and icy conditions left millions of people across Texas and several other states without power yesterday as grid operators took unprecedented steps to protect the electric system from a wider failure.

More than 4 million Texas homes and businesses lacked electricity as of early this morning, according to PowerOutage.US, and President Biden declared a state of emergency in the state over the weekend.

A blast of frigid air in Texas and the central U.S. caused a spike in electricity and natural gas use as people huddled at home to stay warm. Though the cold snap was expected, power producers struggled under the extreme winter conditions and, in certain cases, lacked the gas to fuel power plants. Some wind turbines weren't able to operate.

The Electric Reliability Council of Texas, the state's main grid operator, drew much of the attention given the extent and duration of outages in its region. ERCOT said it was dealing with limited gas supplies and frozen wind turbines Sunday when more generating units tripped offline overnight amid deteriorating weather conditions. It had already seen new record winter peak demand Sunday.

ERCOT entered its highest level of emergency operations around 1:25 a.m. local time yesterday, leading to controlled outages that often lasted many hours instead of an hour or less. The grid operator said outages likely would persist into today as it seeks to return to normal operations.

Dan Woodfin, ERCOT's senior director of system operations, told reporters yesterday that a majority of the generators that went offline during the night before the controlled outages or yesterday morning were "thermal" units that were fueled by gas, coal or nuclear. Of the 34,000 megawatts of generation forced off during the winter event, the grid operator said about 20,000 MW was thermal, with about 14,500 MW of wind.

Power cuts seen by customers didn't necessarily rotate as planned because of the quantity of outages needed, according to Woodfin. He said electricity companies prioritized service to hospitals and

emergency responders. That meant some customers in the ERCOT region lacked power for much of yesterday — and faced uncomfortable or dangerously cold conditions at home last night.

The Southwest Power Pool, which manages the balance of electricity in all or parts of 14 states, said it turned to controlled outages for the first time in its history. Lanny Nickell, executive vice president and chief operating officer at SPP, called the move "unprecedented." Although load was restored, more interruptions were possible, SPP said.

Having Texans without electricity for hours during extreme conditions amounted to a humbling outcome for the state, which has touted its ability to keep the lights on using a largely self-contained grid that doesn't have the sort of mandated capacity market that pays to have available reserves in some other regions.

Texas' blackouts also will add to a national debate about the changing U.S. power mix, including how extreme cold affected both renewable and fossil fuel generation.

A California warning?
The U.S. grid's security monitor warned in November that strains on power systems could threaten operations.

The North American Electric Reliability Corp., in its winter outlook, said customers in New England and California could face disruptions if extreme weather events pushed fuel supplies for generator too hard.

"For natural gas, demand is growing as a generator fuel source and for traditional winter space heating needs," the report said. "However, generating units that lack alternate fuel sources and/or firm contracts for natural gas supply and transportation may not be able to deliver their dispatched energy production profiles."

It added that the impact of the pandemic on utility workers was stressing maintenance schedules on some grid equipment (Energywire, Nov. 25, 2020).

California utilities were forced to order coordinated rolling blackouts in August, the first such emergency action in two decades, when a severe heat wave throughout the western region resulted in neighboring states reducing power exports, a vital course of California's supply.

A preliminary report by state agencies concluded that existing grid planning processes had not prepared the state for such an unprecedented, widespread heat storm.

Wind and solar resources were not the direct cause of the blackouts, said Arne Olson, senior partner with Energy and Environmental Economics (E3), a consulting firm that advises the California Energy Commission. The state wasn't adequately prepared for unique operating challenges when an extreme weather crisis converged with rising levels of solar power in the state.

10 Ways To Fix The Power Grid

Edward Klump, E&E News reporter Published: March 11, 2021

Nearly a month after an arctic blast crippled Texas' main power grid, questions continue to fly about how to prevent a similar disaster from occurring again.

Gov. Greg Abbott (R) has directed lawmakers to address the electricity crisis during their current session. He and others are also calling for power pricing errors to be corrected and for an overhaul of the grid operator.

But the state doesn't yet have definitive answers on how to reform the grid, protect power plants and change its regulatory structure. The outcome in coming months has national implications as officials, companies and consumers across the country weigh how to prepare for the next disastrous weather event — whether a cold snap, heat wave, drought or hurricane-driven flood.

Plans for reform are focused largely on the region managed by the Electric Reliability Council of Texas, the state's primary grid operator.

The Public Utility Commission of Texas (PUC), which regulates electricity, and the Railroad Commission of Texas (RRC), which regulates natural gas, will have important roles to play.

Here are 10 ways Texas could overhaul its electricity system to help keep the lights on:

Coordinate Gas And Power

Experts across the energy sector say natural gas and electricity interests simply must work better together. That means more coordination among the PUC, the RRC and energy companies.

They could, for example, improve lists of critical energy facilities and make sure one sector doesn't derail the other's ability to deliver energy.

Gas is an important source of home heating in Texas, and close to half of the energy provided on the ERCOT power grid in 2020 came from gas-fueled generation.

But gas wasn't always available at the pressures needed for power plants during last month's crisis. The fuel had the most capacity offline in terms of power generation in the ERCOT region during the winter event.

Cold-weather failures on the gas side and a lack of electricity to power elements of the gas system are among the reasons cited so far. Gas prices skyrocketed amid supply shortages.

Joshua Rhodes, a research associate with the Webber Energy Group at the University of Texas, Austin, also suggested a look at moving power plants further up in line for natural gas during grid emergencies.

That could have reduced heating for homes during the recent crisis, he said, but it likely would have kept power flowing in more places. It's also true that many modern gas furnaces can't run without electricity.

Weatherize Energy Assets

Having power plants unprepared for cold weather was a major reason the ERCOT grid came close to a catastrophic blackout in February.

While some assets had winter preparations, Abbott is calling for change. The governor has made winterizing and stabilizing power infrastructure a legislative priority to mandate and fund. The price tag for that could be substantial, though all plants may not require the same level of treatment.

Weatherizing could involve everything from insulation to applying a heat source to pipes, lines and other equipment, according to a 2011 **report** from staffs at the Federal Energy Regulatory Commission and the North American Electric Reliability Corp. Some plants also could look at having a secondary backup fuel in place.

Fix $9,000 Per Megawatt-Hour

Companies and observers have said there are ways to modify Texas' competitive power market without starting over, though some critics want drastic changes. Sustained wholesale prices of $9,000 per megawatt-hour have created financial havoc in the market in the wake of last month's cold snap.

Legislators are expected to discuss issues with the ERCOT market at hearings again today.

Still, it's not clear that state lawmakers have the appetite this session to engineer something like ending electric deregulation or instituting a capacity market to pay plants to be available.

Concern about prices was evident this week as Abbott added an emergency item for lawmakers to consider — correcting billing issues related to ERCOT. His office said that "includes any inaccurate excessive charges and any issues regarding ancillary service prices."

The PUC previously declined to revise wholesale electricity prices related to a market monitor's report of $16 billion of overcharges. Further pricing discussions may occur, including around ancillary services that involve power reserves contracted in advance.

There's also the question of high natural gas prices. Rhodes suggested that an entity might need to step in if gas prices get too high, meaning a circuit breaker for power prices could also trip a circuit breaker for gas prices.

It's a tricky situation because gas prices don't fall under a price cap like electricity does in the ERCOT region.

Plan For Climate Extremes

Climate change can be a complicated subject in Texas, where oil and gas companies have long held enormous influence.

But discussing new climate realities isn't always a partisan issue. Leaders in industry as well as government have said that Texas has seen storms that overwhelm traditional planning, whether in the form of hurricanes, floods or winter storms.

One lesson of 2021 is that it's wrong to assume another extreme event won't surpass expectations.

Factor In Renewables

Not all generation numbers are the same, which is a common point of tension as renewables become more prominent on the grid.

Planners don't count on wind and solar facilities to run all the time. Instead, ERCOT projects how much intermittent generation can be expected at various points. That power can flow on the grid alongside traditional plants that run much of the time or that can be called upon.

Some in industry say Texas has to find a way to retain sufficient generation that it can dispatch on demand when intermittent sources like wind and solar are at reduced levels, but the debate may not be an easy one to resolve.

It reflects a broader one about the energy transition in the U.S. power sector, as baseload fossil fuel plants come with emissions. To have them continue to play a part in a decarbonized future, carbon capture or other technologies may be needed.

Vistra included some market design ideas in a list of **policy response options** it filed with the PUC to help address grid reliability, such as increasing generation reserve purchases and assigning incremental costs to intermittent renewables. It said costs could be allocated based on the expected reliability of renewable megawatts produced and included in renewables bids.

The fact remains that ERCOT's region boasts a fairly diverse setup. Natural gas supplied almost half of the energy on the ERCOT grid last year, followed by wind, coal and nuclear. Sources such as solar and hydro play small roles, though solar installations are climbing.

Battery storage is still trying to gain widespread traction across the United States, and adding it at strategic locations around Texas could help alleviate issues if not solve everything.

Harness The 'Cheapest Energy'

Better protection against the elements shouldn't be limited to energy infrastructure, according to energy efficiency advocates.

Taking actions to lower people's power consumption at home can help when extreme temperatures send demand surging.

Learn To Rotate

Controlled power outages last month were devastating because, in many areas, they didn't rotate from location to location as originally envisioned. That meant that some residents lost power for days, while others may have only had brief outages or none at all.

During the crisis, ERCOT called for power cuts, and it was up to wires utilities, or the transmission and distribution utilities that control poles and wires, to implement how that was distributed.

Experts said the performance of those utilities must improve.

Link The Grid To Other Regions

The crisis last month spurred debate about whether Texas' largely isolated grid contributed to power outages, with analysts disagreeing about whether integration with other states would have prevented the disaster (***Energywire***, Feb. 19).

Texas' main power region may be able to add limited connections to other regions without triggering new federal oversight or becoming completely tied to other areas.

ERCOT only has a small number of connections to bring in electricity from outside its region at this point. That has helped it remain under the PUC for primary regulation and not the Federal Energy Regulatory Commission. Texas has long enjoyed a level of independence in how it approaches electricity policy, a position that some supporters say decreases costs. Others disagree.

Consider A Secretary Of Energy

Fresh perspectives are coming to ERCOT and its main regulator, the PUC, but far-reaching changes may need more time to build momentum.

Dade Phelan, the Republican Texas House speaker, included reforming ERCOT in his **list** of electric legislative priorities — including that all board members should be required to live in Texas. Still, some critics have grumbled at the idea that non-Texans create an issue on the board.

Another idea is to bring the duties of the RRC and the PUC together under a new body.

Creating a new Texas Energy Commission may not be likely right now, but having it on the radar reflects a desire to change how and to what extent energy is regulated in Texas.

Communicate with the public

Communication — or the lack of it — came up repeatedly during recent Texas legislative hearings on the power crisis.

ERCOT and state officials were faulted for not alerting the public clearly or urgently enough to the potential grid problems. And once the lights went out, it was hard for people to understand when power might return.

Regulators: Utilities To Buy Energy To Prevent Blackouts

Published: February 12, 2021

Utilities will be allowed to buy extra energy and pass on the costs to customers in order to avoid a repeat of rolling blackouts that kicked in last summer when demand outpaced supply, California regulators said yesterday.

The California Public Utilities Commission voted unanimously to authorize Pacific Gas and Electric Co., Southern California Edison, and San Diego Gas & Electric Co. to purchase additional power in the next three months.

Last year, more than 800,000 people were left in the dark during an intense heat wave on Aug. 14 and Aug. 15 after the California Independent System Operator, which manages the state's power grid, ordered the first widespread rolling blackouts in nearly 20 years.

The state's three biggest utilities turned off power without prior warning for about an hour at a time until the emergency declaration ended. Gov. Gavin Newsom (D) demanded an investigation after the outages.

A January report by energy regulators blamed the blackouts on poor planning, an extreme heat wave that blanketed the West and energy market practices that allowed desperately needed power to be exported out of state at the peak of the heat wave.

Critics pointed out that the Public Utilities Commission has yet to clearly say why the energy consumers had paid for was not available last year and what regulators will do to keep utilities accountable.

Others who spoke during public comment session said they worried the rush to get more power capacity by the summer could lead the state to pay utilities to buy more fossil fuel energy when California is trying to move toward more clean energy sources.

The regulators also voted unanimously to require utilities to provide 72 hours of backup power to landline phone and internet service during power outages. The decision follows an order by the Public Utilities Commission last year requiring three days of backup power at cell towers in emergency situations, including electricity shutoffs during fire seasons. — Olga R. Rodriguez, Associated Press

Study Reveals EV Secret: They Are Driven Less Than Gas Cars

David Ferris, E&E News reporter Published: February 8, 2021

Electric vehicles in California logged half the miles on the roads of gas-powered cars and didn't draw the big quantity of energy that grid planners expected, according to a new study.

The results of the study, published today by the National Bureau of Economic Research, feed into a topic of intensifying interest to the new Biden administration and in the states: How many resources should be devoted to supporting electric cars?

Researchers, including Fiona Burlig, an energy and environmental policy professor at the University of Chicago, analyzed utility industry data to reveal how much EVs are actually driven compared with their gasoline counterparts.

The findings surprised the academics. As of four years ago, EVs in the Golden State drove on average 5,300 miles a year, less than half the distance driven by an average gas-powered car. And their energy usage is a small fraction of what state officials assume.

Burlig acknowledged the study has limits. It looked at California's use of EVs in a three-year period ending in 2017. EVs were less popular then; the Tesla Model 3, now the country's hottest-selling EV, had just hit the streets.

The study also didn't consider why electric cars' travel is so constrained. But the researchers have some ideas.

It could be that the drivers, encountering few public charging stations and suffering range anxiety, didn't trust their EVs for longer trips. It could be that households with more than one car look at their

EV as an auxiliary. Or it could be that California's electricity rates, among the highest in the country, made fueling too expensive.

Whatever the reason, there is something about EVs that makes them less convenient.

Past studies out of California — home to about half of all EVs in the United States — have looked at households that have their EV on a separate electricity meter.

That, however, is rare in the real world. Most homes with EV charging stations in the garage don't dedicate a meter to it. Instead, the energy draw is mingled with all other devices, like refrigerators, dryers and lights.

To find how much juice regular EV owners were using, the researchers got the addresses of those who registered new electric cars in California. Then they matched those against the addresses in a massive database of the state's utility customers.

Normally, energy data this specific would be off-limits, but the researchers took advantage of a California law that makes it available to academic researchers.

They found that charging an EV increased electricity usage by 2.9 kilowatt-hours a day compared with an average home.

That number is significant because it is so much less than the state of California assumes it to be. The California Public Utilities Commission, using data from the state's investor-owned utilities, estimated that an EV uses almost three times as much — somewhere around 7 or 8 kWh a day.

They did that by noting how much a home's energy use grew after it got an EV and comparing the result to how much energy that particular model of EV uses as it travels the roads.

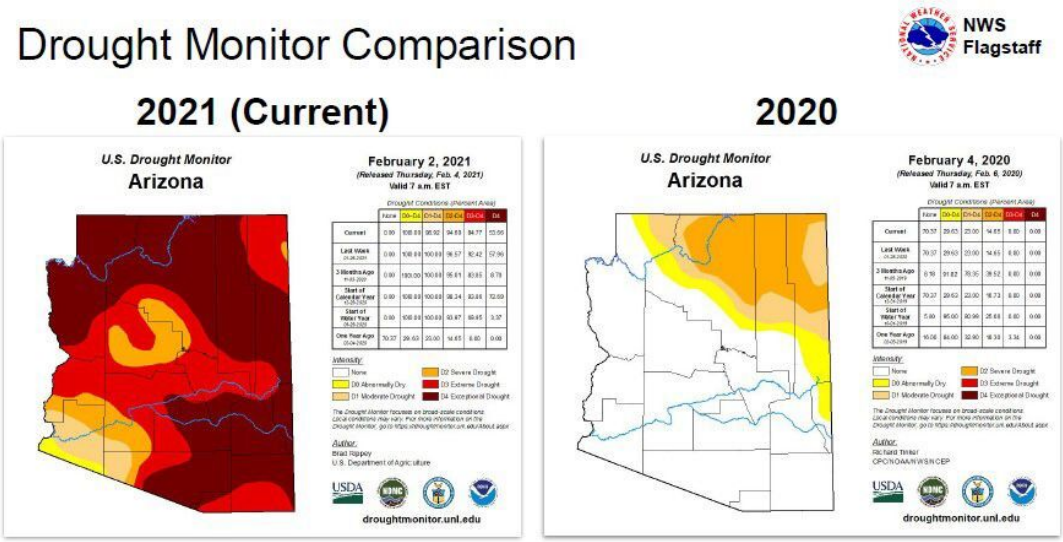
That yielded the finding that the average EV in Northern California drove 5,300 miles a year. By comparison, the National Household Travel Survey, carried out by the U.S. Department of Transportation, estimates the average passenger vehicle travels 12,000 miles a year.

Researchers uncovered another head-scratching tidbit: Owners of Teslas consumed almost twice the kilowatt-hours of other electric brands.

Why is still a mystery, but Burlig has a theory, related to the fact that Teslas have bigger batteries — and much longer driving ranges — than other EVs.

Weather Service Predicts Hot, Dry Months Ahead

By Peter Aleshire, Consulting Publications Editor *Feb 9, 2021*



Comparing the latest drought monitor to the one from this time last year shows how drought conditions worsened across Arizona. Currently 100% of the entire state is in a drought, as opposed to 30% of the state this time last year.

It's official: Buckle up.

Despite the recent snow, the National Weather Service says Arizona will face a mostly normal February, a hot, dry spring and an early, scary fire season.

The widespread snow did dramatically reduce the moisture of the fuels in the forest. Before the storm, we were flirting with an all-time record "energy release component (ERC)" when it comes to the moisture content of plants and downed wood on the forest floor. Now as the snowfall melts, fuels are much wetter than normal for this time of the year.

But that's about it for the good news.

The forecast gives about equal odds February will be either drier and hotter than normal or cooler and wetter than normal. Translation — bet on normal rain and cold for the next three weeks.

After that, things go south.

The odds are we'll have "warmer and drier average conditions" February through April.

And that leads to another sweating-bullets fire season, with higher than normal temperatures and probably normal rainfall. Unfortunately, in May and June normal amounts to zilch. Even in a normal year, Payson gets a total of about an inch of rain for those two months combined.

That adds up to odds of a "significant wildland fire outlook" and a continuation of the current exceptional drought over much of the state.

The above-normal risk of wildfire will start in the lower elevations in April and move up into Rim Country in May and on into the White Mountains in June.

At that point, we'll have to hope the monsoon shows up early and wet, as opposed to last year's "nonsoon." Unfortunately, a lot of the climate models based on the steady rise in average global temperatures suggest the monsoon will likely grow ever more fickle in Arizona. That means we'll have an increase in years with hardly any monsoon as well as years with unusually violent storms. Worst of all will be relatively dry years that nonetheless bring a lot of dry lightning storms — which set fires without dampening the fuels.

What we really need is an entire month of big storms heading into spring — enough to at least temporarily banish drought all across the state. That's what we got last year.

This year — don't hold your breath.

Despite the recent storm, the entire state remains in drought condition. Southern Gila County's in "exceptional" drought and northern Gila County is in "extreme" drought.

The entire state's in drought right now, compared to just 30% at the same time last year, when we were just transitioning from a wet winter to a bone-dry spring and summer.

We're currently in record territory, as measured by how much of the state remains in drought at this point in the winter. Conditions right now dwarf the worst fire seasons on record, including the years that spawned the Wallow, the Schultz, the Yarnell Hill and the Rodeo-Chediski. The closest comparisons would be the Tinder Fire in 2018 and the Bush Fire last year. Last year coming off a much wetter winter, Arizona essentially tied the all-time record for acres burned — nearly 1 million.

So don't put off weeding, clearing brush from around the house, keeping roofs and gutters cleared of leaves and pine needles and packing up that emergency evacuation box.

Fortunately, we've got a little time yet before the scary months — with more or less normal rain and temperatures in February.

Normally, Payson gets 2.3 inches of rain in February, which includes an average of six inches of snow. Normally, the average high temperature is 56 degrees and the average low temperature is 28 degrees.

As of late last week, some streams flowing out of the White Mountains and off the Rim were bolstered by the melting snow while others remain below normal. Salt River at Roosevelt was running at just 46% of normal and the Verde River at 86% of normal. However, Tonto Creek was running at 146% of normal, according to the Salt River Project's daily water report.

Fortunately, Roosevelt Lake remained 82% full, with the downstream reservoirs on the Salt River more than 90% full. The C.C. Cragin Reservoir at midweek was just 20% full, which does not bode well for water deliveries to Payson this spring and summer.

How Markets Are Taking Advantage Of Hydropower's Flexibility

By Cameron Schilling, Vice President, Market Strategies and Regulatory Affairs, NHA

To ensure reliability of electricity delivery, independent system operators (ISOs) and regional transmission organizations (RTOs) often call upon hydropower and pumped storage to provide flexibility outside of standard market products. While there is a process – known as "uplift" – that compensates these projects for such services, that same process is often restricting those assets from operating at their optimal capability and is not necessarily recognizing their true value to the grid.

If these resources are continually relied on to ensure reliability, isn't time for grid operators to start thinking about creating a product that values this service?

Electricity Dispatch Protocol

Competitive regional wholesale electricity markets in the U.S. took shape over two decades ago. Their premise was simple: dispatch electricity across wider footprints to enhance competition and lower costs. To do this, the Federal Energy Regulatory Commission (FERC) created independent system operators (or ISOs and RTOs), who act like air traffic controllers for the grid.

Every day, RTOs forecast supply and demand and then dispatch generators from least costly to most costly. And because most electricity cannot be stored, RTOs must ensure that supply and demand are balanced every five minutes.

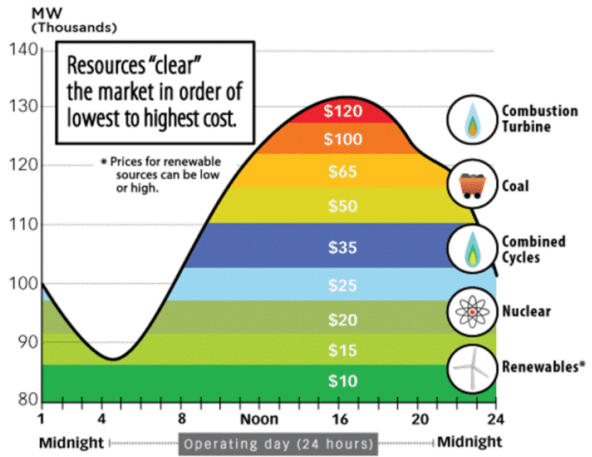
This process has been incredibly successful, saving consumers billions of dollars while maintaining reliability.

So What's the Problem?

There are inevitably times when the RTOs — to ensure the lights stay on — take an action that upsets this least-cost dispatch order. These actions, known as "out-of-market" actions, can involve a variety of scenarios, such as dispatching a more expensive unit, directing a generator to either generate more or less than it wanted to, or keeping a unit from generating to ensure there is enough backup energy.

In many of these situations, RTOs call upon hydro and pumped storage projects, because of their flexibility attributes. In essence, hydro and pumped storages projects are disproportionally relied on to provide services that are "out of market."

Therein lies the challenge. Instead of being allowed to compete on a level playing field in a least cost dispatch situation, these projects are being required to provide services, take actions, and/or operate in ways that may not be the most optimal.



While the grid operators pay for these services, through an "uplift" payment, that payment isn't necessarily reflective of the real value the project provides to the system.

The Deep Dive

Dispatching generators based on cost is a straightforward concept (generators bid in their electricity supply and the RTO stacks them, starting with the cheapest generator (typically nuclear units that must run or wind, solar and hydro that have zero fuel costs). This process ends with the last unit that is needed to meet demand. That unit is the "marginal" unit and it sets the price for every other unit.

However, this process quickly becomes complicated when you factor in the limits of the transmission system (how much the lines can handle), the various operating characteristics of generators (how and when they can start and stop), and various reliability requirements.
While least-cost dispatching works in most scenarios, there are inevitably times when the RTO must call an audible for reliability reasons. Essentially, they must take some action that upsets the least-cost dispatch order and adds costs to ensure the lights stay on.

These "out-of-market" actions could include dispatching a more expensive unit, directing a generator to either generate more or less than it wanted to, or keeping a unit from generating to ensure there is enough backup energy. There are numerous scenarios where this can occur.

The RTOs try to "make whole" the generator that was dispatched out of cost merit with what are called uplift payments. Uplift payments are provided to generators to allow them to recover the costs of the additional action the operator required them to take.

The problem is that out-of-market actions are not reflected in market prices. They do not give generators an opportunity to compete to provide the service. More importantly, uplift lacks transparency and can mask the true system conditions like energy or reserve scarcity. In general, RTOs seek to minimize uplift payments because the uplift costs are socialized to everyone in the market.

The Federal Energy Regulatory Commission (FERC) agrees that uplift is generally a bad thing and recently began tackling the issue by first requiring the RTOs to publish lots of data about uplift. The data shows that hydro and pumped storage are receiving a disproportionate share of uplift payments. For example, in several markets, pumped storage hydro can be a disproportionate recipient of uplift payments due to its inherent flexibility. As shown in the chart below, hydro units in ISO-NE regularly earn 50% or more of their total annual ancillary service revenues from uplift.

While uplift payments represent a small portion (around 1% to3%) of total system costs, these payments can still total in the tens of millions of dollars and disproportionately go to flexible resources like hydropower and pumped storage. For example, in 2019 ISO-NE reported that pumped storage was the only recipient of "posturing credits." Posturing is when the ISO directs a generator to be held back to ensure sufficient reserves on the system — even when it would be more profitable for them to generate.

Bottom line: Grid operators tend to rely heavily on hydropower given its low-cost, flexible characteristics and reliability. According to EIA, hydropower has the fastest start–up times on the grid with most hydro turbines able to go from cold start to full operations in less than ten minutes (some even quicker). By continuing to rely on them for out–of–market actions, the RTO is masking the true value that hydro and pumped storage provide.

What's Next — What Can Grid Operators Do To 'Un-Mask' the True Value of Hydro and Pumped Storage?

Not every out–of–market action can be eliminated. However, if some resources are continually relied on to ensure reliability, then the grid operator should start thinking about creating a product that values the service.

Economists believe that uplift should be reduced and, to the extent practical, markets should provide technology-neutral products that reflect system conditions rather than singling out specific generators and asking them to do things out of market. After all that's what competitive markets are all about.

LNG Global Demand Doubling To 700M Tons By 2040, Shell Energy Report Forecasts *By Rod Walton, Clarion Energy Content Directors 2.25.2021*

Liquefied natural gas (LNG) is not slowing down from asserting a growing global role in power generation, transportation and industrialization as nations try to juggle net-zero carbon goals with grid resiliency, according to many energy experts.

In fact, a new LNG Outlook by energy giant Royal Dutch Shell forecasts that global LNG demand will basically double by 2040. These projections came as Shell Energy executives spoke in a live webcast Thursday morning.

Global LNG demand sustained at close to 360 million metric tons annually in 2020, a slight increase over the previous year. Even so, the market resiliency was considered remarkable in the wake of the global GDP downturn due to the COVID-19 outbreak.

"Overall, global LNG demand is estimated to hit 700 million tons by 2040," reads the Royal Dutch Shell press release preceding the webcast. "Asia is expected to drive nearly 75% of this growth as domestic gas production declines and LNG substitutes higher emission energy sources, tackling air quality concerns and meeting emissions targets."

In the U.S., companies such as Cheniere Energy and Sempra LNG are leading construction of LNG terminals on the Gulf Coast. Houston-based Cheniere, in its earnings report one day ago, forecast that it sees decades of LNG growth ahead.

Much of the domestic LNG market is moved from prolific shale gas plays down pipelines to the gulf coast liquefaction and terminal facilities. Natural gas is converted to LNG by chilling it to minus 260

degrees Fahrenheit (162 degree Celsius), thus making it more concentrated and stable for shipping travel.

The LNG can be moved from the U.S. to international markets which desire it as a lower emitting energy resource than coal-fired power generation. Nations in Asia and Europe have signed deals with U.S. companies to move the LNG and then re-gasify it upon arrival.

The Royal Dutch Shell LNG report noted that global prices started at record lows but rose to six year highs by the end of 2020, driven upward by tightening supplies and higher demand in parts of Asia.

The company estimates that more than half of future LNG demand will come from nations with net-zero emissions targets. "The LNG industry will need to innovate at every stage of the value chain to lower emissions and play a key role in powering hard-to-abate sectors," Royal Dutch Shell's forecast reads.

Utility holding company Sempra Energy's Cameron LNG export facility is now operating with three liquefaction trains at the Louisiana Gulf Coast terminal. Cameron LNG is jointly owned by affiliates of Sempra LNG, TOTAL SE, Mitsui & Co., Ltd., and Japan LNG Investment, LLC, a company jointly owned by Mitsubishi Corporation and Nippon Yusen Kabushiki Kaisha.

Sempra Energy indirectly owns 50.2 percent of Cameron LNG. Sempra LNG and its partners are developing Cameron LNG Phase 2. This will add two additional liquefaction trains and one more LNG storage tank.

The Golden Pass LNG export terminal project is underway along the Texas Gulf Coast. The Golden Pass export terminal is itself a joint venture between affiliates of Qatar Petroleum and ExxonMobil.

It will include the construction of three liquefaction process trains, each with a nominal output of approximately 5.2 million metric tons per year.

ERCOT: Close To 2,000 Generator Outages Reported During Texas Winter Storm

3.5.2021 By Rod Walton, Power Engineering

Hundreds of Texas-based electric generation units reported nearly 2,000 outage events during the February winter storm, according to a new report from grid system operator Electric Reliability Council of Texas.

The ERCOT report this week lists each generation unit from an owner that approved release of the information. The list runs more than 20 pages long and included mostly wind, gas-fired, solar and coal-fired resources.

The lion's share of outages reported by generators happened between Feb. 14-19 as snow, ice and temperatures below zero challenged the electric power and delivery system. ERCOT has been roundly

criticized by Texas customers and its political class, with CEO Bill Magness fired and numerous board members resigning in the wake of the crisis.

Numerous utilities or other power generators opted to not allow that information disclosed, but that omission does not mean they had an outage, the ERCOT letter reads.

Overall, some 52 GW of ERCOT territory generation capacity was lost during the storm, causing outages lasting days, burst pipes and some deaths. Natural gas-fired plants accounted for 27 GW, or more than half of total capacity, while utility-scale wind lost some 18 GW, or 57 percent of that resource capacity, according to ERCOT.

Coal, solar and nuclear also went offline, with the latter two only losing 12 and 13 percent of system capacity, the record shows.

The lost generation forced rolling blackouts and load shedding to cope with the imbalance of supply and demand during the extremely cold weather. Any further loss of grid frequency could have tripped more generation plants offline and led to a total system failure, according to reports.

The ERCOT system oversees most of Texas and is not connected to larger grid interconnections, such as the Eastern and Western Interconnections. Several reports have drawn parallels to the 2011 grid outages and rolling blackouts, but noted that the earlier event is dwarfed by the massive scale of the latest system failure.

California's Approach To Power Pricing Could Discourage Electrification, Experts Fear

Kavya Balaraman@kavya_balaraman Feb. 25, 2021

Dive Brief:

- California's electricity rates — already among the steepest in the country — are set to continue increasing over the course of this decade, and some experts worry the state's approach to pricing could discourage people from switching to electric vehicles and appliances.
- By the end of the decade, bundled residential rates for California's investor-owned utilities are expected to be between 10% and 20% higher than increases that align with the rate of inflation, according to a recent white paper from the California Public Utilities Commission (CPUC) — driven in part by the hefty investments that utilities are making in wildfire prevention strategies.
- Moreover, the state's volumetric pricing structure means that customers are already paying two to three times the actual cost of an extra hour of electricity, a new report found. "Not only is that inefficient in that it's going to discourage electrification, but it's also really unfair because it's disproportionately loading the costs of programs onto poor people," author Severin Borenstein, faculty director of the UC Berkeley Haas School of Business' Energy Institute, said.

Dive Insight:

California's investor-owned utilities currently operate on a "volumetric" pricing model, where fixed costs are recovered through increased per-kilowatt hour rates — a practice that is very different from

the rest of the country and even California's municipal utilities, according to Borenstein. The support for this pricing system has largely come from environmentalists and energy efficiency advocates, on the basis that high electric rates will encourage people to reduce their usage, he added

"That has carried a lot of sway in the state, but as we start facing electrification as a real goal, it starts to become apparent that high volumetric rates are going to discourage people from electrifying — whether it's their vehicle, hot water heating, space heating, [or] clothes dryers," he explained.

And because at this point a typical low-income household consumes almost as much electricity as a wealthy household, adding a few cents per kilowatt hour to cover other costs translates to a much larger share of the income of the latter.

"Effectively, what we're doing is imposing a very, very regressive tax on electricity consumption in order to pay for many programs and infrastructure," Borenstein said.

The report from Next 10 and the Energy Institute indicated that residential prices per kilowatt hour charged by Southern California Edison (SCE), Pacific Gas & Electric (PG&E) and San Diego Gas & Electric (SDG&E) are about 45%, 80% and double the national average respectively.

The report identified three broad categories of factors that have collectively pushing up utility revenue requirements: costs currently funded through rates but not required to serve current load, like energy efficiency programs; costs that are required to maintain the grid, but don't change with increasing or decreasing demand from current customers, like paying to maintain transmission lines; and cross-subsidies among ratepayers, like rooftop solar incentives and low-income programs. In recent years, the impact of energy efficiency and renewables programs has decreased, while fixed costs are contributing to the majority of the cost recovery gap.

"The bottom line is at our current pricing, electric space heating and electric hot water heating and electric clothes drying are just not even close to competitive if you can get natural gas," Borenstein added.

In total, according to the CPUC whitepaper, rates for PG&E, SCE and SDG&E have increased by 37%, 6% and 48% respectively since 2013. And these increases do not account for the billions of dollars the utilities are investing in wildfire prevention, since those haven't yet been fully reflected in rates. The CPUC estimates that between 2021 and 2030, wildfire costs will increase PG&E's revenue requirement by $20.2 billion; SCE's by $14.8 billion; and SDG&E's by $3.9 billion.

These costs are going to push up rates quite significantly over the next ten years, Borenstein noted.

‘It's like peanut butter on toast'

Experts have identified various measures that could keep electricity in California affordable. One strategy, according to Mohit Chhabra, senior scientist at the Natural Resources Defense Council's climate and clean energy program, is proactive electrification, which can put a downward pressure on rates by spreading fixed costs over a larger sales base.

"It's like peanut butter on toast — if you have a fixed amount of peanut butter and you spread it on toast, and you increase the size of the toast, you have a thinner layer of peanut butter," he explained.

The Energy Institute report also identifies measures to address the current inequity in California's pricing structures. One is by raising revenue from sales or income taxes, which would place a higher share of costs on higher-income households.

"We have low-income programs for food and low-income programs for healthcare, and we don't pay for them by raising the price on everybody else — we pay for them through the state budget," Borenstein pointed out.

Another option is to shift utilities to an income-based fixed charge, where wealthier households would pay a higher monthly fee.

These are bold ideas, but it's unclear whether the state legislature and regulators have the appetite for them, Chhabra said.

"But there's aspects of it we can start to integrate — how do you better structure rates to give customers the signal that most of the costs are fixed costs… [and that] the more you use, the more you pay but really if you use more in the afternoon, it costs a lot less for the grid," he said.

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Weekly Fuel Price Watch

Published March 9, 2021 **Author** Staff Writers

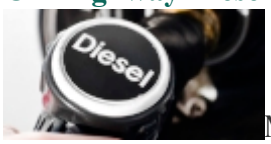
Natural Gas Spot Market (Henry Hub)


March 1: $2.70 per million Btu
One month ago: $3.40 per million Btu
One year ago: $1.74 per million Btu

U.S. Crude Oil Spot Prices (West Texas Intermediate)


March 1: $60.54 per barrel
One month ago: $57.96 per barrel
One year ago: $31.05 per barrel

On-Highway Diesel Prices



March 8: $3.14 per gallon
One month ago: $2.80 per gallon
One year ago: $2.81 per gallon

Retail Gasoline Prices (Regular)

March 8: $2.86 per gallon
One month ago: $2.55 per gallon
One year ago: $2.47 per gallon