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Executive Director Industry Update –April/May 2021

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Wash. Lawmakers Push Pumped Storage Project

Jeremy P. Jacobs, E&E News reporter - Published: April 22, 2021

Washington state lawmakers introduced legislation this week to streamline permitting for a proposed pumped storage hydropower facility in their state.

The bipartisan bill from Sen. Maria Cantwell (D) and Rep. Dan Newhouse (R) would remove what the lawmakers said is a duplicative permitting process for a proposed facility near Grand Coulee Dam.

Cantwell and Newhouse said that currently, both the Bureau of Reclamation and Federal Energy Regulatory Commission have permitting jurisdiction over nonfederal hydropower development at current Reclamation facilities.

That applies to one proposed project: Columbia Basin Hydropower's Banks Lake Pumped Storage Project, a $1.4 billion, 500-megawatt facility.

The lawmakers said the double jurisdiction is inefficient and makes the project more expensive. Their proposal — H.R. 2641 and S. 1246 — would provide Reclamation sole jurisdiction over the project.

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CAISO Board Adopts Final Set Of 2021 Summer Readiness Initiatives

April 26, 2021 - Paul Ciampoli

The California Independent System Operator's (CAISO) Board of Governors on April 21 adopted a final suite of market and operational improvements intended to support grid reliability throughout the West during tight supply conditions.

The board approved the Market Enhancements For Summer 2021 Readiness-Export, Load And Wheeling Priorities Initiative, which will refine the prioritization of energy imports, exports, and transfers through the ISO's balancing authority area (BAA), CAISO noted.

The initiative, slated for implementation in July, “enhances the ISO’s ability to reliably manage intertie energy transactions during electricity shortages such as those that occurred during the August 2020 heatwave that caused rotating power outages,” the grid operator said.

The initiative was the final near-term summer readiness initiative for the Board’s consideration and, if approved by the Federal Energy Regulatory Commission (FERC), will be effective until May 31, 2022.

The ISO is scheduled to begin a regional stakeholder process on a long-term solution to wheeling priorities -- energy transfers through the ISO’s BAA -- in the coming months.

Because the initiative generally affects the real-time energy market, the Western EIM Governing Body last week met to consider the proposal under its advisory role to the Board of Governors and voted to advise the board to take the necessary steps to start a regional stakeholder process and engage the FERC as necessary to proactively create a durable long-term regional solution to the issues relating to export, load, and wheeling priorities.

In March, the Board of Governors and the EIM Governing Body in part, adopted the bulk of market enhancements for summer 2021 readiness to prepare for extreme heat waves that could affect California and the West this summer.

CAISO president and CEO Elliot Mainzer discussed CAISO’s preparation for this summer in a recent episode of the American Public Power Association’s Public Power Now podcast.

Report: 22 Power Lines Could Boost Renewables By 50%

Peter Behr, E&E News reporter - Published: April 27, 2021

A new report by transmission advocates highlights 22 high-voltage power line projects that, if completed, it says could support a 50% increase in U.S. wind and solar generation.

The report comes as the Biden administration is preparing as early as today to announce more details of its plan to have new power lines and high-voltage electric vehicle charging stations built alongside federal highways, according to people informed of the plan. The White House did not respond to a request for comment yesterday evening.

Authors of the report released yesterday, representing the American Council on Renewable Energy, Americans for a Clean Energy Grid and their allies, say Congress could enable the federal government to act like an "anchor tenant" with an initial funding commitment for priority new transmission lines. Then it could sell capacity to renewable developers, getting around the "chicken or the egg" problem where power line and renewable energy projects each wait for the other to commit first, the report said.

The report estimated that building the 22 "ready to go" projects would directly create 600,000 jobs, while building new wind and solar projects to fill the lines would add 640,000 more jobs. The lines would span nearly 8,000 miles and cost $33 billion, the report said.

However, some of the unbuilt or slow-moving projects mentioned in the report are famous already as symbols of the obstacles that have sent President Biden's clean energy team looking for new solutions. The administration's strategy is meant to get around some public and state-level hurdles that have thwarted large new grid projects in the past. But it may risk stirring opposition from some Republican governors who do not stand with the White House's climate policy goals.

Biden's $2.2 trillion infrastructure plan included a proposal for a new federal investment tax credit (ITC) that it said could bring transmission investment "off the sidelines."

"The ITC has been incredibly effective at unleashing private capital for new technologies, and it can do the same thing for transmission," Trey Ward, CEO of transmission developer Direct Connect Development Co. LLC, told E&E News in a recent interview (Energywire, April 1). "An ITC would also put union laborers to work building the grid of the future, which in turn unleashes the construction of large-scale renewables and remote and rural regions."

Biden's "American Jobs Plan" unveiled last month also calls for creating a Grid Deployment Authority at the Energy Department to leverage existing rights of way along roads and railways for high-priority energy infrastructure.

Long lines, long delays

One of the projects on the list in yesterday's report, the SOO Green line, is a case in point of a multistate conduit for renewable power that has run into headwinds despite a dedicated pathway.

The 350-mile circuit would mostly run alongside an existing Canadian Pacific Railway line from Iowa to Chicago's outskirts, moving 2,100 megawatts of wind energy to power about 2 million homes. But developers, who had hoped the railway route would bypass much of the citizen opposition that regularly thwarts transmission projects, are stuck in the region's transmission project approval queue alongside many smaller projects and awaits a green light to connect to the PJM Interconnection LLC, the region's grid operator.

"It's going to take PJM longer to study SOO Green's interconnection than it's going to take us to build this $2.5 billion project," Joe DeVito, president of Direct Connect Development, said recently (Energywire, March 25). "If not for the PJM interconnection delays, we would have been putting shovels in the ground later this year."

Developers haven't given up on "macro" grid projects. The $2.6 billion Gateway West project, proposed in 2007, is under construction and will carry wind power between Wyoming and Idaho. In January, San Francisco-based investors announced funding was in hand to build the proposed U-shaped Western Spirit Transmission line that will connect 800 MW of wind power into the New Mexico grid (Energywire, Jan. 5).

But long lines through multiple states and federal land have faced enervating delays, particularly where the projects move through environmentally sensitive areas or set off landowner opposition.

Another project named in yesterday's report, the Transwest Express, is designed to transmit wind power from Wyoming to Arizona, Nevada and Southern California. Proposed in 2005 by Arizona Public Service Co., the project took eight years to satisfy federal environmental reviews, and federal rights of way, easements and licenses were not completed until 2017 and 2018, according to the project's chronology. The remaining permits, from counties in Utah and Nevada, are expected to be completed this year, the developer said.

In Shift To Renewables, BP Seeks FERC Approval To Sell Power
Miranda Willson & Carlos Anchondo, E&E News - Published: April 27, 2021

BP PLC applied last week to sell power to customers in five U.S. states in the latest sign of the oil and gas giant's shift toward clean energy.

The British company aims to sell electricity from wind, solar and natural gas to customers in Illinois, Ohio, Pennsylvania, Texas and California through a newly formed subsidiary, BP Energy Retail LLC, according to an April 20 filing to the Federal Energy Regulatory Commission. The move would follow BP's ongoing expansion into renewable energy production, including investments in several wind and solar farms.

The company's foray into retail power could be part of a strategy to market lower-carbon energy as fossil fuel use declines, analysts said. Following the announcement of BP's net-zero-by-2050 ambition last year, CEO Bernard Looney has said it's time to "reinvent" the oil and gas company (Energywire, March 2).

In its application to FERC, BP Energy Retail said it "satisfies all of the Commission's requirements to sell power at market-based rates" and intends to begin doing so by June 20. The company listed 13 generating units in its filing, 12 of which are wind and solar farms and one of which is a natural gas plant, as the sources of the electricity it would sell.

While BP will need approval from utility regulators in the states in which it intends to sell power, the application to FERC is largely "a formality" and is almost certain to be approved, Slocum said.

The company bills itself as one of the largest power wholesalers in North America, but it does not appear to have previously offered retail electricity directly to U.S. consumers, according to financial reports.

In addition to its request to sell power, BP Energy Retail filed for permission to provide "ancillary services" in several wholesale markets to support transmission services and grid reliability. That could be an indication that it wants to leverage battery storage and other new clean energy assets, said Joel Eisen, a professor at the University of Richmond.

Experts See Cost Of Wind Power Declining By Nearly 50% By 2050
April 27, 2021 - Peter Maloney

The cost of wind energy is expected to decline by as much as 35 percent by 2035 and by almost 50 percent by 2050, according to a survey conducted by Lawrence Berkeley National Laboratory.

The experts responding to the Berkeley Lab survey estimated median reductions in the levelized cost of energy (LCOE) for wind power of 17 to 35 percent by 2035 and of 37 to 49 percent by 2050.

Participants in the survey focused on five core LCOE inputs: capital costs, operating expenditures, energy output (capacity factor), project life in years, and financing costs (after-tax, nominal weighted-average cost of capital).

The reductions are driven by larger and more efficient wind turbines, lower capital and operating costs, and other advancements, according to the survey findings, which were published in the journal Nature Energy.

The study summarized a global survey of 140 wind experts who considered three types of wind applications: onshore (land-based) wind, fixed-bottom offshore wind, and floating offshore wind. The

anticipated future costs for all three types of wind energy were half of what experts predicted in a similar study Berkeley Lab conducted in 2015.

The survey also revealed that one of the key drivers in cost reductions is improvements in wind turbine sizes. The average capacity ratings of onshore wind turbines are expected to rise to 5.5 megawatts [MW] in 2035 from 2.5 MW in 2019 as rotor diameters and hub heights also increase.

The experts said they expect offshore wind turbines to get even larger, rising to 17 MW on average in 2035, from 6 MW in 2019.

The experts also said they see floating offshore wind gaining market share, growing from its current pre-commercial state to capturing up to 25% of new offshore wind projects by 2035.

Regulatory Roadblocks Stop Dam From Slaking Calif. Thirst
Jeremy P. Jacobs, E&E News reporter - Published: April 28, 2021

As drought grips the West, one Southern California water agency is asking Congress this week for help putting an existing dam to work for its original purpose: water storage.

The complicated case of the Seven Oaks Dam east of Los Angeles is a story of bureaucratic missed opportunities, according to local water managers.

When the 550-foot impoundment was built in the 1990s, it was intended to protect populated areas down the Santa Ana River from intense storm flooding and store water to recharge the area's groundwater aquifers.

More than 20 years later, regulators haven't gotten around to the second part.

Now California is in another critically dry year, revving up the perpetual debate about whether the state needs more dams and water storage.

One local water agency wants Congress to start by using what California already has.

Seven Oaks Dam was built as part of an Army Corps of Engineers response to major floods in the watershed, including one in 1938 that devastated Orange County.

It was originally supposed to be in another location, but the local water district urged the Army Corps to move it so its reservoir didn't interfere with areas used for groundwater recharge.

But when Seven Oaks Dam was completed in 2000, the $450 million project was never fully authorized for anything beyond flood control.

Standing in the way of its dual destiny now is a never-done water conservation feasibility study.

The district has submitted to Congress a $2.5 million appropriations request to fund half the study; the agency would cover the other half. The study would cover how the dam could be operated to provide flood control and conserve water for the district's groundwater aquifers — a major source for the area.

The dam's reservoir can hold at least 115,000 acre-feet.

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'Jugular' Of The U.S. Fuel Pipeline System Shuts Down After Cyberattack
By Gloria Gonzalez, Ben Lefebvre, Eric Geller - 05/08/2021

The main fuel supply line to the U.S. East Coast has shut down indefinitely after the pipeline's operator suffered what is believed to be the largest successful cyberattack on oil infrastructure in the country's history — presenting a danger of spiking gasoline prices and a fresh challenge to President Joe Biden's pledges to secure the nation against threats.

The attack on the Colonial Pipeline, which runs 5,500 miles and provides nearly half the gasoline, diesel and jet fuel used on the East Coast, most immediately affected some of the company's business-side computer systems — not the systems that directly run the pipelines themselves. The Georgia-based company said it shut down the pipelines as a precaution and has engaged a third-party cybersecurity firm to investigate the incident, which it confirmed was a ransomware attack. It first disclosed the shutdown late Friday and said it has also contacted law enforcement and other federal agencies.

(T)he attack is just the latest episode in which hackers have gone after critical systems such as water plants, oil refineries, chemical plants or the electric grid — including a notorious incident in which Russia shut off part of Ukraine's power supply. It's also part of a growing plague involving ransomware, in which hackers demanding payments have crippled targets such as hospitals, police stations or municipal governments.

This could be the most serious successful attack the U.S. has faced yet.

The Department of Homeland Security's Cybersecurity and Infrastructure Security Agency believes that the intrusion is the work of the criminal ransomware gang known as Darkside and not a nation-state, according to a security researcher who requested anonymity to speak freely. Agencies including the FBI, Energy Department, Federal Energy Regulatory Commission and Transportation Security Administration were also responding to the incident, while lawmakers on committees such as Senate Homeland and House Intelligence have requested briefings.

The incident at Colonial underscores how cyberattacks can disrupt the nation's critical infrastructure even without directly corrupting that equipment. Infrastructure operators that suffer computer intrusions often shut down certain functions or facilities to prevent the problem from spreading further. In this way, a seemingly minor breach of a payroll or email system can cause cascading effects that prompt companies to halt production, energy distribution, or other important operations.

Improving cybersecurity in the energy sector has been a key task for several federal agencies. Last month, the DOE and CISA launched an initiative to work with industrial control system operations in the electric sector to improve cybersecurity detection.

Colonial Pipeline is the largest refined products pipeline in the United States, transporting 2.5 million barrels per day, and about 45 percent of all fuel consumed on the East Coast, including gasoline, diesel, jet fuel and heating oil.

The latest development has the potential to put more pressure on the Biden administration and lawmakers as they debate adding cybersecurity funding to the administration's $2 trillion-plus infrastructure proposal, which has faced scrutiny for lacking funds for those needs.

EIA: As Economy Recovers, Electricity Use to Rebound in 2021
Published March 15, 2021 - Author: Victoria A. Rocha

Federal energy officials say electricity use in the United States will rebound a bit this year after falling by nearly 4% in 2020 amid reduced business activity during the COVID-19 pandemic.

Overall, electricity consumption is expected to rise by 2.1% this year, the Energy Information Administration said in its March 9 Short-Term Energy Outlook. The largest growth will be in the retail residential sector, where EIA expects sales to grow by 2.7%.

Colder temperatures in the first quarter of 2021 resulted in higher electricity use compared to the same period in 2020. Despite rolling power outages in Texas and elsewhere last month, EIA estimates residential consumption to be 10% higher than at the same time in 2020.

EIA is also forecasting a 0.7% increase in retail sales of electricity in the commercial sector and a 3.7% increase in the industrial sector.

Turning to generation, EIA predicts the share for renewable energy sources will increase from 20% in 2020 to 21% this year and 23% next year. Total wind capacity in the United States now stands at 118 gigawatts after two record-setting years of additional wind power coming online, according to another recent EIA report, Today in Energy.

EIA expects natural gas to make up a smaller share of electricity generation in 2021 because of higher prices for deliveries of the fuel to power plants. Natural gas will average 36% in 2021 and 35% in 2022, compared to 39% in 2020.

Last month, the Henry Hub natural gas spot price surged to an average of $5.35 per million British thermal units (MMBtu), compared to the January average of $2.71/MMBtu. That was the highest nominal monthly average Henry Hub spot price in seven years.

Salt River Project Consolidates Testing Functions With New Innovation Lab
May 8, 2021 - Peter Maloney

Tempe, Arizona-based public power utility Salt River Project (SRP) recently began operation of its new utility innovation testing laboratory.

The 5,400 square foot Technology Innovation Lab in Scottsdale, Ariz., provides space for SRP employees and contractors working in a variety of functions across the public power utility, including telecommunications; distribution integration; distribution operations; protection, automation and control; power delivery engineering; and power delivery technology services.

The new lab consolidates the lab space that SRP already had. The utility used to have six labs. It now has three. Four of the former labs are now housed in the new lab and two labs – one for customer programs for things such as smart thermostats, the other tests metering technologies – remain at separate locations, though they are being connected to the new lab so they can participate in tests that better replicate the breadth of the utility's operations.

The new lab also has a small classroom space where vendors and SRP teams can conduct training sessions with engineers and technicians. "Training is a huge area of focus for this lab space," Willis

said. SRP's engineers and technicians needed "a central space where employees can come to learn maintenance and commissioning practices in a safe environment."

The idea of creating a single lab for the whole utility had been under discussion at SRP for nearly a decade, but the concept really came together about three or four years ago when SRP hired a consultant to conduct a cyber-penetration test. It turned out it was hard to run a useful version of the test because the representations of the utility's system at the various labs were not consistent.

After about two years of planning, construction of the Technology Innovation Lab began in December of 2019, and it began operation in April 2021.

SRP's protection, automation, and control department is one of the departments that has already started using the lab's capabilities. In collaboration with Intel and other utilities, SRP's team is in the early stages of running tests to evaluate the benefits of virtualizing substation systems.

In the past, substation controls were mostly electro-mechanical with different functions controlled by separate computers. In that configuration, adding a relay to a substation requires a lot of rewiring and physical integration.

If those functions can be virtualized, that is, replicated using software instead of adding another box with dedicated controls to the substation, the utility would be able to perform the same function by adding a new application.

From SRP's perspective, a virtualized solution would help standardize substation hardware, consolidate and centralize functionality, improve employee safety, and reduce capital investment, as well as operation and maintenance costs.

Another huge benefit is being better able to test new equipment, Cormier said. Just because a manufacturer's equipment meets industry standards does not mean it will work well with other components. The Technology Innovation Lab gives SRP the ability to run "end-to-end tests" on new equipment in a more realistic and holistic way, he said.

Washington state passes bill with goal to phase out gasoline cars

Reuters

Washington state lawmakers passed a bill on Thursday setting a target to stop sales of gasoline-fueled vehicles there beginning in 2030, five years sooner than California.

The target is not a firm mandate and is contingent on the state adopting a tax on vehicle miles traveled, a measure to help pay for new transportation infrastructure, according to the text of the bill.

The move by the Pacific Northwest state comes as efforts to boost adoption of electric vehicles are accelerating over concerns about fossil fuels' contribution to climate change.

Automaker General Motors Co (GM.N) has said it aspires to stop selling gas-fueled passenger cars by the same date.

Washington's 2030 electric vehicle goal would kick in once three-quarters of the state's registered vehicles are subject to a so-called road usage charge, according to the bill's text.

The legislation must be signed by Democratic Governor Jay Inslee before becoming law. Inslee's office did not immediately respond to a question on whether he would sign it.

Washington-based environmental activist group Coltura called the passage of the bill a victory for the fight against climate change, saying it would accelerate the adoption of electric vehicles.

Corporation Commission Votes To Strengthen Policies On Power Disconnection
By Emma Richburg | Cronkite News - April 23, 2021

With summerlike heat already here and triple-digit temperatures around the corner, Arizonans are cranking up the air-conditioning in April. As electricity use increases, some Arizona residents who struggle to pay their power bill risk being disconnected.

On April 14, two years after the emergency moratorium was put in place, the commission voted 3-2 to preliminarily approve a package of measures regulating when utilities can shut off service for nonpayment. Commissioners Lea Márquez Peterson, a Republican, joined Democrats Sandra Kennedy and Anna Tovar to vote yes, while the two Republican commissioners Jim O'Connor and Justin Olson voted no.

The proposals give utility companies the choice between a blanket moratorium from June 1 through Oct. 15 or a temperature-based threshold that prohibits shutoffs on days when temperatures reach 95 degrees.

Commissioners voted 5-0 to ban disconnections for customers who owe less than $300 for electricity and $100 for natural gas and unanimously approved an increase in solar projects for low-income multifamily housing.

After public comment, the commission will vote to revise or finalize the rules next year, and they would take effect by summer 2022.

The rulemaking is likely to be completed in time to take effect in summer 2022. In the meantime, APS and Tucson Electric Power are not allowed to turn power off for customers from June 1 to Oct. 15.

Annual Peak Loads Are Shifting To Winter; ACEEE Report Details How Utilities Can Manage

Published April 23, 2021 - By Robert Walton, Reporter

Dive Brief:

- Growing numbers of utilities will soon see electricity demand peak during the coldest winter months, highlighting the need for customer-side technologies and energy efficiency to keep the grid stable, according to new research from the American Council for an Energy-Efficient Economy (ACEEE).
- Electrification, including space heating, water heating and electric vehicle (EV) charging, could double or triple winter utility loads, according to ACEEE. A combination of aggressive demand-side management (DSM) resources, however, could help to slash peak loads by more than a third in some areas.

- Duke Energy could find up to 1,400 MW of targeted winter DSM in its North Carolina and South Carolina territories, according to a study by Tierra Resource Consultants. "It is a significant resource we can bring to bear, but it is clearly nascent," firm principal Tom Hines said during a recent discussion of ACEEE's conclusions.

Dive Insight:

Electrification is a key strategy to eliminating carbon emissions, but it also means utilities will need to add generation and address shifting load profiles. The collapse of the Texas grid, when faced with a historic cold snap, highlights the importance of the issue, according to ACEEE Utilities Program Manager Mike Specian.

Most utilities in the United States currently see peak demand in summer, to address cooling loads, but, Specian said that will change. Some utilities already face winter peaks, particularly in the Northwest but also in the upper Midwest, Vermont and parts of the Southeast, he said.

"Many states will trend towards becoming winter-peaking by mid-century," Specian said during an April 15 webinar discussing the study's findings. New England could become a winter-peaking region by 2040, he said, driven by residential space heating.

ACEEE's report concludes that as air conditioners and buildings become more efficient, summer loads may drop. And with natural gas furnaces being replaced with electric heat pumps, and solar production lower during the winter, grid stress during the coldest months will increase.

ACEEE considered a range of DSM measures in the study, including: home weatherization, residential smart thermostats, commercial advanced rooftop controls and energy information management systems, efficient lighting, water heating demand response, managed EV charging, load shedding through HVAC programs, and the installation of air source and geothermal heat pumps.

Summer and winter peaks are driven by different technologies, last different durations and are met by different fuels, warned Specian. That means utilities must adjust their approaches. "We need to be mindful that the solution set for winter peaking constraints is going to generally be different than mitigating summer peaks," he said.

ACEEE's report finds utilities and other DSM program administrators can mitigate winter peaks and constraints "by drawing upon and scaling up the few existing programs that specifically target winter peak demand reductions through energy efficiency and demand response."

In New England, ACEEE found a comprehensive package of DSM resources could reduce load peaks by 34.2% by 2040, while a business-as-usual slate of resources will only lower peaks 6.7%.

California's Dilemma: How To Control Skyrocketing Electric Rates While Building The Grid Of The Future

New ideas include income-based rates, publicly-funded infrastructure, utility entrepreneurship, and customer-funded wildfire insurance.

Published April 26, 2021 - Herman K. Trabish, Contributing Editor

California Public Utilities Commission (CPUC) President Marybel Batjer says the state will not let skyrocketing electricity rates threaten reliability or the state's policy goals.

But affordability is a growing concern as California works toward a "future grid" and a dynamic new power system to meet the climate crisis and related extreme weather events, stakeholders and CPUC Staff maintain. Rates rising far faster than inflation are straining the budgets of vulnerable customers and new approaches that protect policy goals and customer bills are urgently needed, they agree.

Protecting ratepayers as California transitions to distributed energy resources (DER) and economy-wide electrification "will require aggressive actions," according to a report released by CPUC Staff in February.

At a day-long CPUC hearing, California utilities proposed cutting wildfire costs and raising revenues outside rates. Stakeholders proposed shifting the costs of supporting DER and electric vehicles (EV) out of rates to other sources of revenues. Others proposed breakthrough rate designs that could make managing costs more equitable.

The upward pressure on rates could force unwelcome choices on policymakers, especially to protect low to moderate income (LMI) customers, according to the Staff report.

Driven by clean energy and electrification mandates as well as utility investments in system modernization, residential rates across California have risen faster than inflation since 2013, Staff found. And due to Net Energy Metering (NEM) and other DER incentives, impacts have been worse for LMI customers, it said.

By 2030, Pacific Gas and Electric (PG&E) residential rates will be 40% higher than if they had followed inflation, Staff projected. Southern California Edison (SCE) rates will be 20% higher and San Diego Gas and Electric (SDG&E) rates will be 70% higher.

LMI customers are "like canaries in a coal mine," said Jennifer Dowdell, an energy policy analyst for customer advocacy group The Utility Reform Network (TURN). "Rates are growing so much faster than wages that even the middle class may soon need rate relief."

"Rate based capital investments in transmission and distribution are accelerating," and wildfire mitigation costs have "significant rate impacts," Staff found. The report projected wildfire mitigation costs from 2021 to 2030 will cost PG&E $23.7 billion, SCE $17.2 billion, and SDG&E $3.9 billion.

Another factor is the costs of the state-mandated net energy metering (NEM) 2.0 program that compensates DER owners for electricity sent to their power systems. Net-metered generation was over 15% of PG&E, SCE and SDG&E residential electricity consumption in 2019, recent research showed.

An independent evaluation of the NEM 2.0 program from 2017 to 2019 found the policy "increases non-participant bills," Staff reported. In that period, an overall system evaluation found total benefits of $7.96 billion and total costs of $9.46 billion. A separate evaluation of customer bill impacts found total benefits of $7.58 billion and total costs of $20.58 billion.

Transportation and building electrification "can lead to lower household energy costs" where the cost of electricity is lower than the price of gasoline or natural gas, but the high "up-front" costs of EVs and DERs are a "barrier to participation" for LMI customers, Staff found. That leaves them with

"incremental costs" as revenues covering system costs from more affluent customers who adopt DERs fall.

In addition, Staff found reducing the state's 46 MMT 2030 power sector emissions target to the proposed 38 MMT target would add $0.006/kWh to $0.008/kWh to all customers' rates because more emissions reductions would add new system transition costs and accelerate current patterns.

Revenue requirements for transmission system modernization also put major upward pressure on rates, Staff said. From 2016 to 2021, the three IOUs' requirements will increase 38.1%, Staff projected. And "every dollar put into the transmission rate base costs ratepayers in excess of $3.50 over the life of a transmission asset." Transmission use charges are also driving rates up.

Concerns about rates are important, but investments in DER offer "net benefits to the California economy" that Staff has overlooked, stakeholders responded.

A shift to a high home electrification scenario would add 4.7% to 5.8% to the total 2030 utility revenue requirement because investments would be needed for distribution system upgrades to manage the new load. But utilities' 8.5% increase in 2030 electricity sales could lower average rates, Staff acknowledged. And EV ownership with or without managed charging programs reduces driving costs.

But affordability is at risk, and "it is hard to pinpoint places where we should cut back," said CPUC Deputy Executive Director for Energy and Climate Policy Edward Randolph. Wildfire mitigation and transmission development are critical to avoiding outages, "and investments in clean energy are necessary to meet state policies, have minimal bill impacts, and could save money over time," he added.

Stakeholders have proposed two paradigm-shifting rate designs to address Staff concerns.

Stakeholder rate design proposals address a utility bill's fixed charge and volumetric per-kWh charge, but in different ways.

With electricity sales declining from "energy efficiency, energy conservation, and customer generation, the bill's fixed charges do not cover fixed costs," Staff said. Higher volumetric rates have been approved to cover fixed costs for infrastructure, DER and LMI subsidies, energy efficiency programs, and wildfire mitigation.

The Regulatory Assistance Project (RAP) Advanced Residential Rate Design proposes time-varying rates to cover costs not met by the fixed charges, RAP Associate Mark LeBel said. They are more granular than California's current time-of-use (TOU) rates and "are incentives to use electricity when it costs least and export electricity when the costs are highest because it is most valuable to the system," he said.

RAP's bidirectional charge is a per kWh charge on imports and exports that matches the evolving grid's two-way power flows, LeBel said. It would vary according to netting and other options. And it could also be implemented incrementally, with increasingly nuanced time periods and sophisticated customer segments.

This rate design is only necessary in places like California and Hawaii with high penetrations of DER that are shifting costs, he added. "It does not solve all the challenges, but it can be part of a package of solution strategies."

RAP's proposal does not solve California's fixed costs challenge, said Severin Borenstein, director of UC Berkeley's Energy Institute and professor of Business Administration and Public Policy.

Putting policy objectives in the volumetric part of utility rates or increasing all customers' fixed charges is "regressive," added Borenstein, who is also a member of the California Independent System Operator Board of Governors.

The price of electricity should reflect and cover the "social marginal cost" of each unit of electricity, he said. That is the cost of generation, transmission, distribution and greenhouse gas emissions in a unit of electricity plus the still-unpriced societal impacts of pollution from producing electricity.

California rates are "way above that" because fixed costs, including those for infrastructure, wildfire mitigation, and LMI and DER, are paid for through the volumetric charges, he said during a Feb. 24 CPUC hearing. A more "progressive" rate would recover fixed costs from an income-based fixed charge that would be low for LMI customers and higher for the more affluent.

The fixed charge innovation is a more complicated rate design because it requires income information, and customers' privacy would require protections, Borenstein acknowledged. But California's tax authority and its utilities could resolve those obstacles.

The Borenstein data shows today's rate structure is regressive, LeBel agreed. But his rate design has implementation challenges, like income verification, that are probably only worth taking on at high levels of DER penetration, he said. And it "increases the rates of higher income customers, which gives the people who can most easily afford to defect from the grid the biggest incentive to do that."

Recent research does show a high volumetric charge could increase grid defections in high penetration markets, Borenstein said. "But this is a fixed charge increase. The wealthiest customers might face an $1,800/year fixed charge, but would have a $0.10/kWh volumetric charge. That is less reason to defect than the $0.40/kWh volumetric charge forecast for California."

There is a simpler approach, Borenstein said. California could add electricity to the programs it offers, through the state budget, to help LMI citizens with food and healthcare, but that would be "politically difficult" because it would have tax impacts. "There is no easy solution," he said. An income-based fixed charge "is the best alternative."

But the CPUC hearing produced other alternatives, including utility proposals for cutting costs and increasing revenues as well as stakeholder proposals for alternative funding.

The rapid rise in California's rates makes finding solutions urgent, utilities and stakeholders agreed.

"We are in a rate crisis now with electricity costs growing faster than inflation, inequity rising, and wildfire costs coming," said CPUC Public Advocates Office Electricity Pricing and Customer Programs Branch Manager Mike Campbell.

PG&E is working on ways to reduce costs and generate other sources of revenue, said PG&E Vice President of Regulatory and External Affairs Robert Kenney. "Operational efficiencies" may save nearly $1 billion/year through 2025, and $973 million in revenue is expected from agreements with wireless provider SBA Communications for the future use of PG&E transmission towers, he said.

In addition, customer-funded wildfire self-insurance "can be a near term solution until better wildfire control technologies bring premiums down," said SCE Senior Vice President of Strategy and Regulatory Affairs Carla Peterman.

SCE's "tower of insurance" to meet the $1 billion coverage now mandated by California law may include layers of commercial insurance, bonds and reinsurances, and "premiums in some layers could exceed utility losses," Peterman, a former CPUC commissioner, said. "Self-insurance could be more affordable."

Self-insurance eliminates insurance company administrative costs and profits, and "if claims are low, new premiums will be minimal," she added. Savings could be "in the hundreds of millions of dollars over a multi-year period."

SDG&E's wildfire mitigations are the industry standard and it is investing in new technologies to improve its capabilities, said Scott Crider, the utility's chief customer officer. And the investments' "risk-spend" balance is focused on reducing the need for future wildfire mitigation capital expenditures.

The political barriers mentioned by Borenstein to leveraging public revenue for public programs like wildfire mitigation and building and transportation electrification may not be impossible to overcome, some stakeholders said.

"Many of the costs in rates are to achieve societal benefits," TURN's Dowdell said. "Traditional utility rate making is one of the most expensive and regressive ways to obtain those benefits."

When California utility rates were relatively low, they could be used for policy objectives, "but the state does not have that luxury anymore," Dowdell said. A better concept may be California ownership of assets like large-scale long duration storage, new transmission, and EV charging infrastructure needed to achieve state goals. Others saw this idea as having varying prospects of success because it could increase the tax burden.

"There's not one magical strategy," Dowdell added. "Tax revenues to pay for those investments could come from California's general fund or the state and municipalities could use their bonding authority for specific infrastructure projects."

At the close of the hearing, the CPUC's Randolph complimented the stakeholders' proposals but also cautioned broadly about unintended consequences as commissioners consider which to implement.

On the other hand, "the commission needs to recognize that even the right investments will put upward pressure on rates, but it also needs to look at the consequences of not investing," CEERT's Caldwell said.

Leaked Docs: Gas Industry Secretly Fights Electrification
Benjamin Storrow, E&E News Reporter - Published: Monday, May 3, 2021

In public, Eversource Energy likes to tout its carbon neutrality goals and its investments in offshore wind.

But officials from New England's largest utility struck a different tone during an industry presentation in mid-March. Instead of advocating for lower emissions, company officials outlined a defensive strategy for preserving the use of natural gas for years to come.

Natural gas is "in for [the] fight of it's life," said one slide presented at the meeting and obtained by E&E News. It also called for a lobbying campaign, saying that "everyone needs to contact legislators in favor of NG." Another slide asked how the industry could "take advantage of power outage fear" to bolster gas's fortunes.

Eversource is identified in the presentation materials as the co-leader of a national "Consortium to Combat Electrification," run out of the Energy Solutions Center, a trade group based in Washington. The slides identified 14 other utilities involved in the effort and said the group's mission was to "create effective, customizable marketing materials to fight the electrification/anti-natural gas movement."

The presentation comes amid a rising tide of policies aimed at banning natural gas in buildings.

Eversource executives sought to distance themselves from the messages conveyed in the presentation, saying they don't reflect the views of the utility's leadership. Yet the company's private assessment, delivered to industry insiders, underscores the challenge facing gas providers as state and federal policymakers set their sights on net-zero emissions targets.

More than 40 cities in California have taken steps to restrict gas use in new buildings. Seattle followed suit in February. That has prompted a growing number of Republican-led states to preemptively block municipal gas bans (*Energywire*, Feb. 2).

Massachusetts looks like the next battleground. The state recently enacted a climate law to eliminate greenhouse gases by 2050. That will require zeroing out emissions associated with heating and cooling buildings, which accounted for roughly 27% of the state's greenhouse gases in 2017, according to the most recent Massachusetts data.

When Massachusetts regulators mapped out a path to zero emissions late last year, they concluded that swapping out oil- and gas-fueled furnaces, boilers and water heaters for electric alternatives constituted the most cost-effective strategy.

That represents a potential threat to companies like Eversource, which last year paid $1.1 billion to acquire the Massachusetts-based assets of Columbia Gas, a subsidiary of NiSource Inc.

'Aggressively Decarbonize'

It's unclear which of those outcomes is destined for Eversource. The company is an offspring of New England's deregulated energy markets. It does not own power plants but instead buys electricity on the wholesale market and sells it through its transmission and distribution system in Massachusetts, Connecticut and New Hampshire. In 2020, its electricity segment earned more than $1 billion, amounting to more than 85% of the company's business.

Eversource has invested in three offshore wind projects in response to New England's efforts to expand the clean energy sector. Electrification is a growth opportunity for the utility. But the revelation that Eversource and other utilities are girding for a political battle over gas's future shows how power companies remain wedded to fossil fuels even as they take steps to green their businesses.

When *The Boston Globe* first reported the company's involvement in the secretive consortium last month, Eversource officials said that they had withdrawn from the group. The utility later ran a full-page ad in the paper showing an offshore wind turbine and touting Eversource's pledge to become carbon neutral by 2030.

A spokeswoman for the utility reiterated that message in a statement to E&E News, saying the presentation given by employees of the company's gas division in March was not reflective of Eversource's position.

But the call to arms by Eversource, whether authorized or not, reflects a wider movement within the gas industry.

Several industry representatives acknowledged that gas companies are fighting growing efforts to ban or limit new natural gas hookups. They challenged the assumption that electrification will automatically reduce emissions in the building sector and argued that natural gas infrastructure remains an important tool for achieving net-zero goals.

The advantages of the gas system are threefold, said Erin Blanton, a senior Columbia researcher who authored the report. The infrastructure already exists and could be used to deliver clean fuels like renewable natural gas or hydrogen. A molecule like hydrogen can easily be stored and delivered at times of peak demand. And the use of natural gas infrastructure could help reduce stress on the electric system, which will have to grow dramatically to meet rising demand from transportation and other sectors.

Other experts are skeptical. The existing natural gas system is already riddled with leaks and runs through major population centers, said Gordon, the RMI expert. That infrastructure would likely need to be replaced to carry a lighter and more volatile molecule like hydrogen, which presents serious safety concerns.

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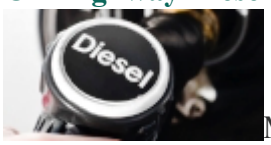
Natural Gas Spot Market (Henry Hub)

April 27: $2.91 per million Btu
One month ago: $2.52 per million Btu
One year ago: $1.68 per million Btu

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

April 26: $62.02 per barrel
One month ago: $60.93 per barrel
One year ago: $12.17 per barrel

On-Highway Diesel Prices



May 3: $3.14 per gallon
One month ago: $3.14 per gallon
One year ago: $2.40 per gallon

Retail Gasoline Prices (Regular)

May 3: $2.89 per gallon
One month ago: $2.86 per gallon
One year ago: $1.79 per gallon