Changing Climate, Changing Utilities

Extreme Weather, Wildfires, Technology, and the Electric Grid

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Electric utilities are facing new challenges in the United States. Here in the West, we are beginning to experience the direct impacts of climate change, through extreme weather, droughts, reduced snowpack, and wildfires. A hotter, drier climate intensifies wildfire risk and severity. Electric utility infrastructure—like high-voltage transmission lines—have always posed fire risks, but those risks are now much greater than when those facilities were initially constructed. This has led utilities to commence preventative emergency disconnection of electricity service as a tool to mitigate the risk of utility infrastructure sparking deadly and devastating wildfires. These interruptions in service, while reducing wildfire risk, also pose significant hardship on broad populations of utility customers who depend on reliable access to electricity.

In reaction to these intensifying operational risks from electric utility infrastructure and unpopular impacts on customers, two regulatory trends are emerging. First, utilities are seeking to be more proactive in maintaining infrastructure and proposing new wildfire mitigation programs. Second, regulators and utility customers are turning to distributed energy resources as a way to improve the reliability and resilience of electricity service. This article explores both trends in the context of Colorado, a wildfire-prone state with vertically integrated regulated utilities.

Climate Change Exacerbates Physical and Financial Grid Risks

The U.S. power grid has been dubbed "the biggest machine on Earth." Over 7 million miles of transmission and distribution lines are used to deliver electricity to homes and businesses across the country. Electric utility operations can be generally broken down into three major categories of infrastructure: generation, transmission, and distribution systems. Utility-scale generation assets, including thermal power plants, solar arrays, hydroelectric generators, and wind farms, produce most of the electricity delivered to the utility's customers. Transmission lines carry this electricity at a high voltage across long distances, where it is delivered to the distribution system via substations. Here the electric voltage is "stepped down," and is then transmitted across lower-voltage transmission cables to individual homes and businesses for use. Whereas transmission lines are like the interstate highway system of electricity, the distribution system is more akin to the side streets and alleyways of a residential neighborhood. Both transmission and distribution infrastructure have the potential to spark wildfires in increasingly populated areas.

Climate change has heightened the risk of utility-sparked wildfire, particularly in the western United States. Scientists now believe the American Southwest is in the midst of a "megadrought" not experienced for 1200 years as a result of man-made climate change. During the last 30 years, the amount of land burned by wildfires annually has nearly doubled across the West, according to the National Academy of Sciences. The five costliest wildfires in U.S. history have all occurred since 2017 and are all in western states. And these risks are only anticipated to intensify. As noted by the 2014 Third National Climate Assessment, "Increased warming, drought, and insect outbreaks, all caused by or linked to climate change, have increased wildfires and impacts to people and ecosystems across the Southwest. Fire models project more wildfire and increased risks to communities across extensive areas." *Climate Change Impacts in the United States: The Third National Climate Assessment* (Jerry M. Melillo, Terese C. Richmond & Gary W. Yohe, eds., U.S. Global Change Research Program, 2014). These risks are particularly acute in Colorado, which has an exceptionally high proportion of developed properties in extreme wildfire risk zones.

In another western state, California, the 2018 wildfire season was the second-most destructive on record, scorching more than 1.67 million acres, a figure since eclipsed by the 2020 wildfire season, which saw 4.3 million acres destroyed. The deadliest 2018 wildfire—the Camp Fire, which destroyed the town of Paradise, California—was triggered by a downed power line operated by Pacific Gas and Electric (PG&E). Utilities, regulators, consumers, and NGOs around the country have observed the fallout from the devastating Camp Fire. The lesson is clear: In a warming and drying climate, the delivery of electricity can present new and intensified risks—both physical and financial—that were not contemplated when the grid was first developed.

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The Role of the Regulatory Compact

To understand the actions and incentives of electric utilities, and their appetite for change, one must first understand the relevant regulatory process. In Colorado, electric utilities are vertically integrated, meaning that a single utility both operates the electric generation resources and is responsible for delivering and selling electricity to customers. These investor-owned public utilities can only operate with the permission and approval of the Colorado Public Utilities Commission (PUC). Public utilities operate within the bounds of the so-called regulatory compact: They are granted a franchise by the PUC to be the exclusive electricity provider within a defined service territory and, in exchange, are fairly compensated through rates set by the PUC. Typically, this compensation provides for the recovery of the "just and reasonable" costs of providing service, along with an opportunity to earn a return on investments made to serve customers. Specific regulatory approval must be obtained in advance of a utility making certain large investments, such as building a new power plant or a large transmission line. For these expenditures, a "certificate of public convenience and necessity" must be acquired from the PUC. Other categories of investments do not need advance approval, and their costs can be recovered so long as they are made in the "ordinary course of business."

Utilities also have an obligation under the regulatory compact to provide safe and reliable electric service. In Colorado, the PUC requires electric utilities to meet specific quality-of-service requirements. Quality-of-service tariffs track metrics related to electric service quality, such as interruption frequency, responsiveness to customer complaints, and the average time necessary to restore power after an outage. A failure to provide service of sufficient quality can result in financial penalties to the utility.

Addressing the Imminent Threat of Fire and Liability: Service Interruptions

On November 8, 2018, a portion of PG&E's Caribou-Palermo transmission line fell from a hook and sparked the Camp Fire. The Camp Fire went on to burn 153,336 acres, killing 85 people and destroying 18,804 structures—including the entire town of Paradise, California.

PG&E faced unprecedented civil and criminal liability as a result of its role in the Camp Fire. It pled guilty to 84 counts of manslaughter, was ordered to pay a $1.9 billion civil penalty, and is still struggling to emerge from its subsequent and controversial bankruptcy case. The public is demanding changes to utility business practices to prevent these kinds of tragedies from being repeated in the future. Utilities—particularly utilities serving arid western states—can no longer ignore the threat of wildfires when operating and maintaining the electric system.

After the devastating 2018 fire season, California adopted new approaches to curb utility-caused wildfires. One solution that emerged is "de-energization," which means that under certain weather conditions, utilities would proactively cut power to lines that they anticipate may fail in order to reduce the likelihood that their infrastructure could cause or contribute to a wildfire. Without an advanced grid monitoring and communication system, it can be hard for a utility to target power shutoffs to discrete areas. In September and October 2019, several of California's utilities de-energized power lines during dangerous wildfire conditions for extended periods of time. Millions of customers were impacted—with PG&E's shutdown alone cutting off power to more than 2 million customers for a period of four days.

The 2019 public safety power shutoffs were successful in preventing fires, but they were wildly unpopular with customers. The four-day shutoff in PG&E's territory resulted in significant impacts to California's economy, with losses estimated to be $2.5 billion. Complaints of inadequate notice, and a failure to warn vulnerable customers, such as those with medical conditions, led the California PUC to investigate the 2019 power shutoffs and consider enforcement action. As a result, the California PUC established new guidelines utilities need to follow before de-energizing the distribution system.

While improved notice can help mitigate the impacts on customers, it will not resolve all issues. Many customers cannot sustain prolonged power outages without impacts to their health or financial welfare. A widespread power outage is terribly disruptive for any community, but customers with health conditions who rely on medical equipment that requires electricity and businesses with goods that require constant refrigeration face critical risks from prolonged outages. Prolonged de-energization is an unacceptable mitigation measure to deal with wildfire risk on an ongoing basis.

Wildfire Mitigation Plans: Grid Investments to Reduce Risk

The risk associated with wildfires can no longer be ignored. Large transmission lines carry massive amounts of electricity long distances at high voltages. The majority of the distribution grid is comprised of service wires strung across wooden utility poles. Aboveground distribution systems can be more cost-effective than underground distribution systems but are more prone to failure during extreme weather. Wooden utility poles are prone to snap or fall during periods of high winds, which can spark fires. Nearby vegetation can also fall on the distribution wires, causing damage that also may spark a fire. In some jurisdictions, utilities face strict liability for wildfires sparked by downed power lines. The 2018 Camp Fire is one example, but downed power lines were also to blame in the 2019 Woolsey Fire impacting Los Angeles County and the 2007 Witch Fire impacting San Diego County. Both events led to significant civil liability for the utilities involved, with L.A. County seeking to recover a reported $100 million in losses from Southern California Edison, and San Diego Gas and Electric paying out more than $900 million in claims from homeowners and local governments impacted by the fire.

One strategy to decrease the risk of fire from the grid is to improve the safety of the distribution grid itself. Some utilities are looking to mitigate wildfire liability risks by developing comprehensive Wildfire Mitigation Plans. Public Service Company of Colorado, a division of Xcel Energy and the state's largest electricity provider, is looking holistically at risks faced by its distribution system and system upgrades that can help mitigate these risks. Under this approach, three factors contributing to wildfires are being independently analyzed to develop a wildfire mitigation strategy. Wildfire risk zones are identified using vegetation data maintained by the state's forest service. Adverse weather conditions are being tracked by measuring the number of "red flag warning" days, a period when warmer temperatures, low humidity, and stronger winds combine to produce an increased risk of fire danger. Finally, targeted upgrades to the utility's distribution system are planned, including the installation of reclosers along portions of the distribution system in high-risk areas. Reclosers function like a circuit breaker in a home and can automatically shut off when a disruption occurs. Advanced reclosers can communicate with a centralized system and can be triggered to shut off remotely if appropriate. Using these three factors, the utility is in the process of developing a plan to respond to wildfire conditions in specific areas when the risk of a fire is high.

Upgrading the distribution system with this advanced technology may allow a utility to selectively target smaller portions of the distribution system for de-energization when wildfire conditions persist. While this technology has not yet been tested, it could present an important, less disruptive alternative to widespread power shutoffs.

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At the same time, proposals for significant new investments in the distribution grid under the guise of "wildfire mitigation" deserve close scrutiny from regulators. Wildfire mitigation and climate adaptation costs are likely to persist and substantially increase over time, as the risks associated with climate change become reality. Regulators assessing these utility requests for wildfire mitigation cost recovery should avoid creating new financial incentives to perform basic system maintenance that the utility already should be completing. Regulators should also be wary of adopting new cost recovery frameworks for wildfire mitigation that work against other important policy goals, such as reducing a customer's financial incentive to pursue energy efficiency.

Finally, regulators should keep in mind that increased wildfire risk itself is an indirect result of utilities' decades-long reliance on fossil fuel sources of electricity generation that emit large amounts of climate-changing greenhouse gas emissions. Across the United States, the electricity sector is still the leading source of greenhouse gas pollution across the economy, due to its reliance on coal and other fossil fuels. Many electric utilities today are announcing ambitious clean energy goals, but the industry has historically been an influential opponent of greenhouse gas pollution limits and other clean energy and climate policies at the state and federal levels. Traditionally, the few utility regulators that have considered the impacts of climate change when making decisions about generation resources and other utility operations have focused solely on climate change as imposing *externalized* costs on society, in the form of health impacts, habitat loss, etc. But wildfire risks demonstrate how climate change also poses *direct* costs on electric utility consumers, which regulators should be taking into account across a variety of regulatory proceedings.

Utilizing Distributed Energy Resources to Manage Risks and Reduce Impacts

Thoughtful utilization of distributed energy resources and the distribution grid itself are creating a new opportunity to manage wildfire-related risks and to reduce customer impacts from blunter tools like de-energization. Distributed energy resources are those that interconnect or operate on the distribution grid level, such as rooftop solar, small-scale energy storage systems, energy efficiency, demand response, electric vehicles and other flexible loads, and microgrids. Customer demand for clean, distributed energy is growing rapidly, further increasing the complexity of designing, operating, and regulating the electricity grid we all depend on for safe, reliable electricity. What was once a centralized system, where electricity was generated in one location and delivered to customers in a one-way flow through transmission and distribution lines, is now evolving. Distributed energy resources can allow electricity to be generated and exported back to the grid throughout the distribution system. Customer-sited energy storage systems can be deployed and reduce the demand for grid energy. The distribution grid, which was once a one-way street, must now adapt to accommodate these new sources of generation and changes in demand.

Sweeping regulatory changes are required to fully examine the distribution system and explore the role of emerging technologies to upgrade the grid and improve reliability even in the face of increased wildfire risk.

In Colorado, there has historically been little regulatory oversight into a utility's investments in its distribution system. These investments have been considered to be within the "ordinary course of business" and therefore subject to only minimal oversight by regulators. No advance Commission approval is required for distribution system upgrades. Theoretically, investments in the distribution grid can be challenged after the fact by disallowing cost recovery for imprudent investments. These types of cost recovery challenges are difficult to mount by a prospective party, unlikely to be successful, and—because they're backward-looking—do not drive deployment of new alternative technologies on the distribution grid.

Thus, the distribution system planning process occurs entirely within the utility itself, with little to no regulatory oversight. This planning includes routine maintenance and repair and identifies areas where the utility predicts additional capacity will be necessary. To identify areas that may require additional investment, the utility assesses its current and planned infrastructure in light of expected electricity demand. Increased demand for electricity—which can be the result of adding new customers or each individual customer simply consuming more—can overwhelm existing capacity of various grid components, such as substations and feeders. Under an "ordinary course of business" approach, utilities perform whatever maintenance and capacity upgrades they deem necessary and recover the costs of those projects from customers through electricity rates.

This lack of transparency and oversight, coupled with a regulatory model that discourages adoption of distributed energy resources, has hampered adoption of technologies that could reduce and manage the impacts of increased wildfire risk. However, in Colorado, policymakers have been pushing utilities to take a harder look at how distributed energy resources can be effectively deployed as distribution grid assets.

For example, the PUC recently adopted a rule requiring utilities to consider deploying energy storage systems as "an alternative to construction or extension of distribution facilities where appropriate." 4 Colo. Code Regs. § 723-3-3207(b). This new rule could require a utility to review deployment of a microgrid as an alternative to traditional distribution system upgrades. However, this evaluation need only occur within the utility's existing, internal distribution system planning process, which is not public. Therefore, it is nearly impossible for either stakeholders or regulators to assess whether this consideration is actually occurring or whether it's being conducted appropriately. In addition, the requirement applies only to energy storage systems as a potential alternative, ignoring other distributed energy resources that may serve as viable alternatives to traditional "pole and wire" investments, such as energy efficiency, demand response, or distributed generation.

Sweeping regulatory changes are required to fully examine the distribution system and explore the role of emerging technologies to upgrade the grid and improve reliability even in the face of increased wildfire risk. In 2019, the Colorado legislature passed Senate Bill 19-236, which, among other things, directs the Colorado Public Utilities Commission to promulgate rules creating a new, public distribution system planning process. By law, utilities must file distribution system plans with the PUC. These plans must include (1) historical data about energy use; (2) existing peak demand; (3) a description of the historical and forecasted future adoption of distributed energy resources; (4) anticipated distribution system investments; (5) a description of the utility's consideration of non-wire alternatives, including for new neighborhoods or housing developments; (6) load forecasts; (7) an assessment of cyber and physical security risks to the grid; and (8) cost recovery proposals. Colo. Rev. Stat. § 40-2-132(1)(e) (2019). The Commission can also require utilities to submit any other information the Commission deems relevant. The Colorado PUC is currently assessing various approaches to distribution system planning and recently issued its notice of proposed rulemaking late in 2020.

With the passage of S.B. 19-236, the Commission has an opportunity to adopt a new distribution system planning paradigm that allows significantly more transparency into the distribution planning process and creates new opportunities to assess cost-effective alternatives to traditional pole and wire distribution grid upgrades. But it also creates a forum in which regulators and stakeholders can address emerging issues on the distribution grid, including wildfire risk. Notably, the distribution system planning process in Colorado will need to include an assessment of physical risks to the distribution grid, which should include the increasing risks wildfires pose to the functionality and reliability of the distribution grid. If done correctly, distribution system planning is an opportunity to assess which specific locations on the distribution grid are most at risk of causing a fire and to manage those risks. But even in situations where a utility's distribution infrastructure has been well maintained and the risk of sparking a wildfire is low, distribution system planning is an opportunity to prepare for impacts of wildfires on electricity service itself. In arid climates like Colorado's, wildfire is a perennial concern. With longer, hotter wildfire seasons across the western United States, it is reasonable for utilities to be proactively assessing how wildfires will impact their ability to provide reliable electricity service, and to be developing products, such as microgrids and behind-the-meter energy storage programs, that can reduce the impact of wildfires on electricity service.

Microgrids as a Resiliency Solution

One component of distributed system planning is assessing how distributed energy resources can be deployed to improve system resilience and reliability, including the ability to manage wildfire risks. Microgrids are one possible solution for managing service interruption risks posed by wildfires and other natural disasters. A microgrid is a localized grid system that can disconnect from the traditional electrical grid and operate autonomously. Microgrids are an interconnected portion of the grid but can break off and operate on their own using a local energy generation resource. Because they can operate independently from the central distribution system, microgrids can offer an important resiliency function in times of power outage. A microgrid can serve as a source of backup power for a large customer, a neighborhood, or even a small community, depending on its design. Deploying microgrid technologies effectively requires enhanced knowledge of the constraints of a utility's distribution system, as well as a customer's need for electricity.

Customers with strict quality-of-service requirements, such as hospitals, have historically relied exclusively on diesel generators to provide backup power in the case of an outage. Diesel generators can be inefficient, have negative local air-quality impacts, and contribute to climate change. A microgrid powered by renewable energy resources, such as a solar array and a battery storage system, presents a cleaner alternative, but the technical limitations of these systems are still unknown.

Public Service Company of Colorado was recently granted regulatory approval to invest in and test a series of community resiliency pilot projects powered by renewable resources. The pilot program will test seven projects serving a variety of customers, including small cities, large commercial customers, and Denver International Airport. Many of these projects are located in areas of the state that have experienced repeated service outages due to their remote location, mountainous terrain, or location in a wind-impacted area. These demonstration projects will present an opportunity to test the efficacy of microgrids to provide reliable electric service when a system outage occurs.

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In this changing environment, both utilities and regulatory agencies are having to innovate in how they build, manage, and utilize the electricity grid. Utilities, faced with potential liability from wildfires, must reassess their construction and maintenance of the grid to manage risk. PUCs have to look at system safety and reliability metrics in new ways and carefully assess utility requests for costly new investments in the grid intended to reduce wildfire risks. Regulators also need to evaluate how distribution system planning and new service offerings from utilities and third parties can keep the lights on while keeping customers safe. Colorado is taking steps to make these changes now, with an eye towards modernizing both the distribution system and the regulations that control it.

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