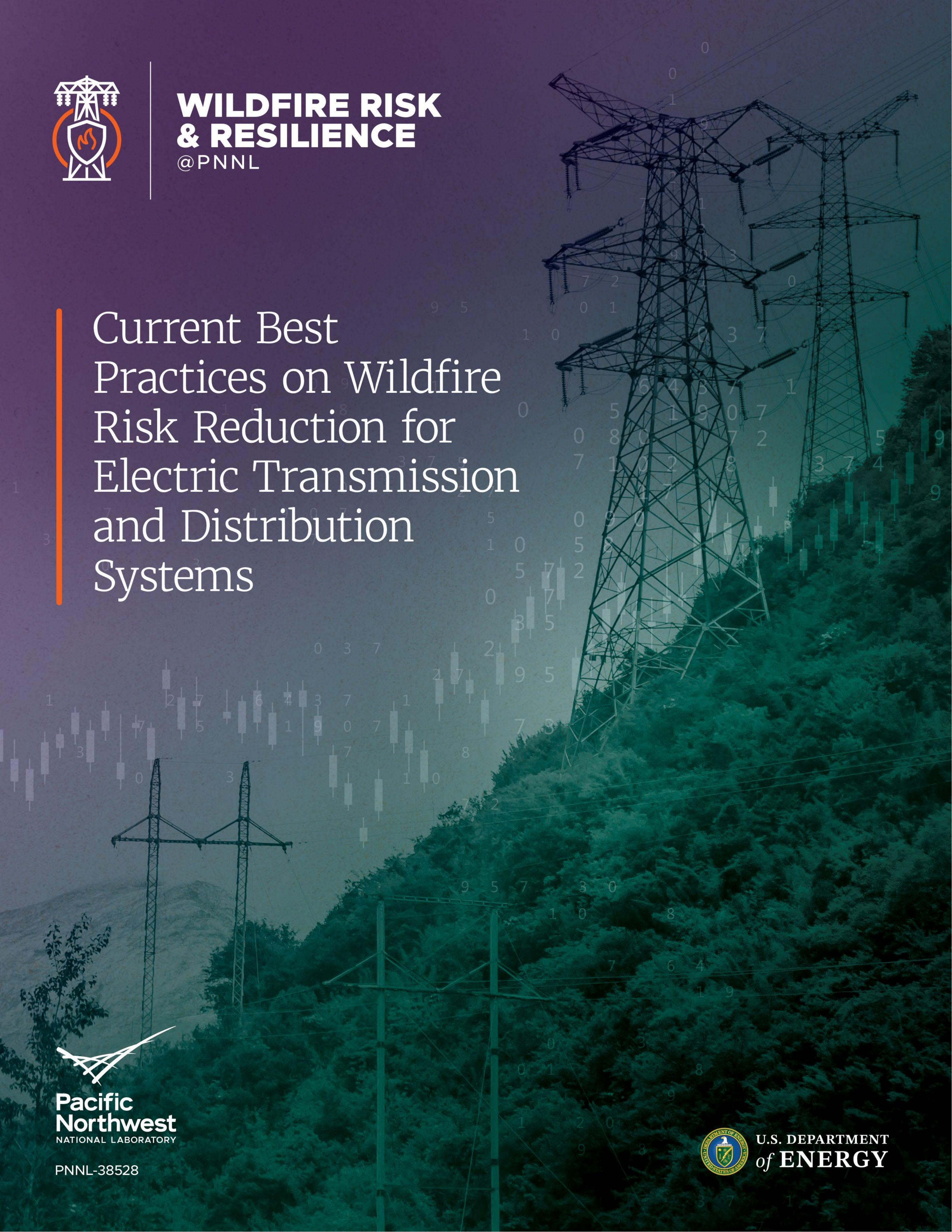

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Current Best Practices on Wildfire Risk Reduction for Electric Transmission and Distribution Systems

Pacific Northwest NATIONAL LABORATORY

PNNL-38528

U.S. DEPARTMENT of ENERGY

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Current Best Practices on Wildfire Risk Reduction for Electric Transmission and Distribution Systems

February 2026

André M. Coleman
Christopher M. Chini
Arielle J. Catalano
Saptarshi Bhattacharya
Vishvas H. Chalishazar
Rebecca S. O'Neil
Kyle B. Larson
Ilan Gonzalez-Hirshfeld
Lee M. Miller
Kerry G. Abernethy-Cannella
Troy M. Saltiel
Jerry D. Tagestad
Jess Kincaid
James J. Yoon
Pranab Roy Chowdhury
Irena M. Netik

U.S. DEPARTMENT of ENERGY

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Executive Summary

This report provides a set of current best practices in response to Section 4(d) of Executive Order 14308, Empowering Commonsense Wildfire Prevention and Response. Section 4(d) directs the Secretary of the Interior, the Secretary of Agriculture, the Secretary of Energy, and the Federal Energy Regulatory Commission to consider initiating rulemaking proceedings “to reduce the risk of wildfire ignition from the bulk-power system without increasing costs for electric-power end users.” The information contained herein is expected to be used in conjunction with other materials made available at the Federal Energy Regulatory Commission Wildfire Risk Mitigation Technical Conference (Docket No. AD25-16-000), with direction to the North American Electric Reliability Corporation to make recommendations for future actions. In the past decade, a higher frequency of wildfires have been evidenced with a magnitude, intensity, speed, and size that haven’t historically been observed. These high-intensity wildfires pose an escalating threat to people, property, infrastructure, and ecosystems. Wildfires are no longer an issue limited to the Western United States—all areas of the country are being affected, and the resulting direct and indirect costs are substantial. Regions with traditionally low wildfire occurrence, including the Northeast, Southeast, Southern Great Plains, and Midwest, reached an inflection point in 2019–2020, exhibiting significantly higher fire occurrence over the past five years (2020–2024) compared to the preceding decade. Furthermore, many regions of the country are also experiencing an expansion of fire activity outside of their traditional fire season. Therefore, high-wildfire-potential conditions are exhibiting longer durations, thus increasing the risk of wildfire occurrence throughout the year.

On average, over a 15-year period (2010–2024), known utility-caused wildfires represented 2.4 percent of all wildfire ignitions in the U.S., leading to an average range of 104,000 to 390,000 burned acres/year (NIFC, 2025a, 2025b). For perspective, the average area burned from electric utility-caused ignitions represents a long-term annual average of 3.9 percent of the total U.S. burn area considering all ignition sources. The burn area percentage from electric utility started fires is relatively small when compared to the national totals; however, the direct and indirect costs are significant, due in part to where the fires are occurring. While there is no single comprehensive source on U.S. electric utility expenses around wildfire, it is estimated that the direct infrastructure losses, liabilities for utility-cause ignitions, insurance, losses in power revenue, and investments in mitigation, infrastructure hardening, enhanced operations, and labor expansions cost $126–$150 billion/year (2025 dollars; Thomas et al., 2017; National Oceanic and Atmospheric Administration [NOAA], 2021; Bayham et al., 2022; Warner et al., 2025; Franklin et al., 2025). For context, across federal, state, local, industry, and private entities in the United States, wildfires cost $355–$764 billion/year, which includes preparedness actions, suppression efforts, evacuations, direct damage, legal costs, economic and tax base losses, health impacts, long-term recovery, insurance, and research and development (2025 adjusted dollars; Thomas et al., 2017; Borgschulte et al., 2020; Miller et al., 2021; Bayham et al. 2022; Congressional Budget Office, 2022; Crowley et al., 2023; Cotality, 2024; NIFC, 2024; Warner et al., 2025; Franklin et al., 2025).

Although addressing wildfires originating from utility infrastructure is a priority concern in this directive, fire encroachment on energy systems from fires initiated elsewhere also causes damage to electrical infrastructure or prompts preemptive public safety power shutoff actions or emergency de-energization. This dual risk, both from and to the utility, and from and to adjacent lands, creates a complex positive feedback loop. This highlights the need for utilities to incorporate an entity-specific set of best practices to avoid ignitions and for utility right-of-way-adjacent, multi-jurisdictional entities to manage the landscape in a unified, holistic manner to benefit all landowners and stewards (local, state, federal, private) by reducing the severity and impact of catastrophic wildfire. These best management approaches not only reduce the risk to utility and ratepayers but also have broader positive impacts on the public, economy, and environment. These efforts include improved service reliability and public safety, reduced costs, economic benefits from reduced wildfire impact, and enhanced wildlife habitats and invasive species control.

The objective of this report is to provide an overview of existing and emerging best practices currently employed or planned by utilities for wildfire mitigation, demonstrating how these efforts align with the executive order's emphasis on reducing electric utility–caused wildfires while also balancing cost-effectiveness. Additionally, while most practices in utility-developed wildfire mitigation plans focus on risk reduction through robustness and operational reliability, this report also discusses best practices for resilience, as per Executive Order 14239, Achieving Efficiency Through State and Local Preparedness, which includes recovery and long-term system transformation. Utilities that have historically been operating in high-wildfire-risk environments mitigate risks in three ways: 1) avoid asset-based ignition and thus impact to areas outside of their right-of-way corridor, 2) implement multifaceted resilience tactics to withstand or minimize wildfire encroachment and impacts on energy assets, and 3) plan and strategize for timely system restoration to minimize customer outages. For the purpose of this report, "best practices" are defined as those activities and implementations that have generally been shown to be effective at reducing the risk and effect of wildfire ignition. The best practices are adopted from publicly available utility wildfire mitigation plans from the United States and Canada, recent findings from wildfire risk reduction research, and industry engagement. It is important to recognize that each utility is distinct in its assets and system configuration, operations, risk interface, tolerance for risk, resourcing, mitigation actions, and preparedness and restoration practices. Thus, no single set of practices will produce the same outcomes for every utility. Instead, a curated set of practices needs to be adopted and structured in a methodical way to balance ratepayer and taxpayer investments to an acceptable level of risk. If a risk manifests, the established preparedness and recovery practices are crucial for reducing its impact and minimizing restoration times. Most utilities that are actively engaged in wildfire risk reduction efforts recognize that the cost of mitigation is small compared to the costs of fighting wildfires or rebuilding communities. Investment in wildfire mitigation practices, in itself, is seen as a best practice to reduce liability and increase system reliability and safety.

Per Executive Order 14308, this report focuses predominantly on transmission-level best practices for wildfire reduction. Many utilities, however, manage both transmission and distribution systems, which are equally important for preventing outages and damage from wildfires. Therefore, relevant best practices for distribution systems are also identified. This report frames its analysis within a three-phase resilience framework:

Pre-Event: Resilience as Robustness

This phase focuses on proactively hardening the electric grid and its surrounding environment to prevent ignitions. Robustness is the first line of defense in preparing a system to be more resilient. Key practices include the development of utility wildfire mitigation plans, which are dynamic, living documents that guide a utility's risk-reduction efforts. The report highlights several critical components of these plans:

- **Wildfire Risk Modeling and Weather Forecasting:** Different types of wildfire models exist over different scales of space and time to represent wildfire risk and potential consequences to utility infrastructure and surrounding non-utility high-value resources and assets. The integration of historic, real-time, and forecasted data on weather and fuel moisture with data on vegetation characterization, terrain, and historical wildfires drives informed decision-making and mitigation strategies.

- **Engineering Design and System Hardening:** This involves physical upgrades to infrastructure, such as undergrounding power lines, installing advanced conductors to prevent sparking, and replacing or wrapping aging wooden poles with more resilient steel, ductile iron, or composite alternatives.
- **Vegetation Management:** This is a crucial practice that involves removing or trimming vegetation near power lines to prevent contact with powerline conductors. The use of advanced technologies like uncrewed aerial systems and lidar can aid traditional review cycles, enabling more efficient and accurate inspections and management of vegetation.
- **Asset Management and Inspections:** Regular, in-depth inspections of equipment state and health are essential. Using a combination of traditional and advanced methods to assess the condition of assets allows for early identification of potential points of failure.
- **Supply Chain Management:** Supply chain management for electrical grid components works toward the timely availability, current and future sourcing, current and future pricing, and identification of supply chain risks to create a more resilient grid.
- **Multi-entity Coordination:** Coordination among local, state, federal, Tribal, and private partners enables utilities to apply expert knowledge, efforts to achieve common goals, action plans, and resources to collaboratively manage the landscape and resources to minimize wildfire risk.

Peri-event: Resilience as Graceful Extensibility

This phase covers real-time operational responses to high-risk conditions or active fire events. The goal is to enable decision-making to reduce ongoing risk, minimize impacts to the power systems, and ensure safety. These real-time or near-real-time efforts occur in the order of seconds to hours to enable decision-making or automated actions. The primary focus areas are as follows:

- **Enhanced Situational Awareness:** The use of a network of tools—including real-time weather monitoring systems, visual surveillance systems, and grid data—and short-term lead forecasts and subsequent risk assessments provides operators with comprehensive analysis and an up-to-the-minute view of conditions, system anomalies, and potential fire threats.
- **Adaptive Grid Operations:** The ability to automatically or semi-automatically adjust grid settings in response to evolving conditions, including the use of faster trip mechanisms that de-energize circuits in milliseconds when a fault is detected, significantly reduces the risk of a line arcing and initiating new fire starts. Furthermore, this provides safe conditions for fire services or other emergency responders when they are near powerlines and corridors. These targeted de-energizations are a more precise alternative to widespread public safety power shutoffs.

Post-Event: Resilience as Rebound

This final phase focuses on the recovery and rebound process, including adaptation for improved system function and resilience. Key practices include the following:

- **Inspection and Restoration:** After a fire, utilities conduct comprehensive inspections of their infrastructure to assess damage and begin the restoration process.

- **Post-fire Vegetation Management:** Quickly removing compromised trees to avoid vegetation fall-in risk, reestablishing and managing the vegetation, and performing engineering control in areas that have been burned are necessary steps for minimizing or preventing secondary faulting and ignition, flash floods, debris flows, and landslides.
- **Performance Metrics and After-Action Reporting:** Tracking performance metrics involves measuring and analyzing data to evaluate the effectiveness of response and recovery efforts following a wildfire event. This process allows utilities to evaluate restoration speed, assess program effectiveness, improve safety measures, and inform future mitigation strategies and emergency preparedness plans.

The best practices sections (Sections 3.0–5.0) are followed by discussions on regulatory frameworks, policy, the utility planning paradigm (Section 6.0), and cost considerations (Section 7.0), acknowledging the non-technology and engineering challenges of implementing a more reliable and resilient system. The multifactor cost considerations of implementing utility-focused wildfire mitigations, credit ratings, and liabilities—as well as implementing risk mitigation co-benefits, cost-effectiveness measures, and landscape-level, multi-entity cost-sharing—are addressed at a high level.

The report concludes with a sampling of emerging best practices (Section 8.0) that includes topic areas of practices that currently have limited evidence of operational application, are being piloted, or are still in the research and development phase.

Acronyms and Abbreviations

AAR	after-action report
AAR/IP	after-action report and improvement plan
AGT	advanced grid technology
ALERT	advanced live emergency response technology
BLM	Bureau of Land Management
CAL FIRE	California Department of Forestry and Fire Protection
CEATI	Centre for Energy Advancement through Technological Innovation
DOE	U.S. Department of Energy
DLR	dynamic line rating
EGP	Enterprise GeoSpatial Portal
EPRI	Electric Power Research Institute
EPSS	Enhanced Powerline Safety Settings
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FIRMS	Fire Information for Resource Management System
GIS	geographic information system
GOES	Geostationary Operational Environmental Satellite
GWIS	Global Wildfire Information System
HCE	Holy Cross Energy
ICS	Incident Command System
IEEE	Institute of Electrical and Electronics and Engineers
ISO	International Organization for Standardization
IVM	integrated vegetation management
IWRMC	International Wildfire Risk Mitigation Consortium
MAVF	multi-attribute value function
ML	machine learning
MODIS	moderate resolution imaging spectroradiometer
NASA	National Aeronautics and Space Administration
NERC	North American Electric Reliability Corporation
NIFC	National Interagency Fire Center
NIMS	National Incident Management System
NOAA	National Oceanic and Atmospheric Administration
PG&E	Pacific Gas and Electric Company

NWS	National Weather Service
PSPS	public safety power shutoff
PUD	public utility district
RAWS	USFS Remote Automatic Weather Station
RFW	red flag warning
ROW	right-of-way
ROWSC	Right-of-Way Stewardship Council
RSE	risk-spend efficiency
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAR	synthetic aperture radar
SCE	Southern California Edison Company
SCADA	supervisory control and data acquisition
SDG&E	San Diego Gas & Electric
TTX	tabletop exercise
UAS	uncrewed aerial system
USFS	U.S. Forest Service
VIIRS	Visible Infrared Imaging Radiometer Suite
WECC	Western Electricity Coordinating Council
WFDS	USFS Wildland Fire Decision Support System
WMP	wildfire mitigation plan

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Acknowledgments

The Pacific Northwest National Laboratory team gratefully acknowledges the support and guidance of the U.S. Department of Energy's Grid Deployment Office in developing this report to support the implementation of Section 4(d) of Executive Order 14308, Empowering Commonsense Wildfire Prevention and Response.

The authors extend their sincere appreciation to David C. Parsons, Anne Egger, and Patrick Blake for their leadership, direction, coordination, and review throughout this effort. The authors also recognize and thank the external reviewers from the Bonneville Power Administration, North American Electric Reliability Corporation, Sacramento Municipal Utility District, the Southeastern Power Administration, the Western Area Power Administration, the Western Electricity Coordinating Council, and Xcel Energy for their thoughtful technical input and constructive feedback, which significantly strengthened the quality and clarity of this report.

This work was sponsored by the U.S. Department of Energy under the direction of the Grid Deployment Office.

Preface

This report, *Current Best Practices on Wildfire Risk Reduction for Electric Transmission and Distribution Systems,* was prepared to aid in the response to the requirements of Section 4(d) of Executive Order 14308, Empowering Commonsense Wildfire Prevention and Response.

Acknowledgment of Time Constraints

Given the critical nature of this topic and an ambitious 2.5-month timeline for completion, this document represents a best-effort synthesis of current wildfire risk reduction practices across the electric transmission and distribution sector.

The rapid turnaround necessitated covering a wide array of highly technical and evolving subjects, including utility-specific operational programs, advanced risk modeling, and complex regulatory frameworks. While we have relied on extensive literature reviews, subject matter expertise, and external expert input, the compressed schedule has limited the opportunity for deeper investigation and rigorous, confident verification of every detail across all topics.

Invitation for Feedback

We welcome and strongly encourage the prompt submission of any feedback, comments, corrections, or suggested additions from a variety of stakeholders. Your expertise is vital to ensure the long-term accuracy and utility of this work with future versions.

Please direct all correspondence regarding this report to Dr. André Coleman at wildfire@pnnl.gov with the subject line "Wildfire Executive Order: Feedback for Technical Report on Utility Best Practices."

Your collaboration will be instrumental in refining this document into a comprehensive and reliable resource for advancing wildfire resilience nationwide.

Revision History

2025-11-21: Report released publicly.
2026-02-04: Page break added at Section 6.0; TOC page numbers updated; date removed from front cover graphic.

1.0 Introduction

This report provides a set of current best practices in response to Section 4(d) of Executive Order 14308, Empowering Commonsense Wildfire Prevention and Response. Section 4(d) directs the Secretary of the Interior, the Secretary of Agriculture, the Secretary of Energy, and the Federal Energy Regulatory Commission (FERC) to consider initiating rulemaking proceedings "to reduce the risk of wildfire ignition from the bulk-power system without increasing costs for electric-power end users." The information contained herein is expected to be used in conjunction with other materials in the FERC Wildfire Risk Mitigation Technical Conference (Docket No. AD25-16-000), with possible direction to the North American Electric Reliability Corporation (NERC) to make recommendations for action. This document primarily emphasizes best practices for transmission systems, while also acknowledging the complexity and unique challenges associated with each utility operator. Therefore, the intention is not for each best practice noted herein to be relevant to all utilities. Instead, the document takes a survey approach, highlighting opportunities utilities *could* pursue to increase their resilience to wildfire threats. Additionally, to broaden the utility of this document, at the direction of the U.S. Department of Energy (DOE), current best practices for both the bulk-power and distribution systems are included herein and are distinguished accordingly as to whether a given practice applies to transmission systems, distribution systems, or both. This report does not consider generation sources, but many of the concepts would equally apply.

The likelihood, intensity, and impacts of wildfires initiated by electric power systems pose an escalating threat to people, property, infrastructure, and ecosystems. Wildfires are no longer an issue limited to the Western United States—all areas of the country are being affected, and the resulting costs are substantial. For example, regions with traditionally low wildfire occurrence, including the Northeast, Southeast, Southern Great Plains, and Midwest, hit an inflection point in 2019–2020; over the past 5 years (2020–2024), the fire occurrence in these regions is anywhere from 9-times to over 70-times higher than it was the 10 years prior (the National Interagency Fire Center [NIFC], 2025a). Furthermore, many regions of the country are also experiencing an expansion of fire activity outside their traditional fire season, for which the drivers and timing vary depending on the region (Table 1). Therefore, high-wildfire-potential conditions persist for longer, increasing the likelihood of wildfire throughout the year.

On average, over a 15-year period (2010–2024), known and reported utility-caused wildfires accounted for 2.4 percent of all wildfire ignitions in the U.S., resulting in an average range of 104,000 to 390,000 burned acres/year (NIFC, 2025a, 2025b). For perspective, the average area burned from electric utility-caused ignitions represents a long-term annual average of 3.9 percent of the total U.S. burn area, considering all ignition sources. Note there are extremes not represented in these long-term numbers—such as the 2024 Smokehouse Creek fire in the Texas panhandle that burned 1.1 million acres due to a combination of a decayed wood power pole and extreme fire weather conditions. The burn area percentage from electric utility-started fires is relatively small compared to the national totals; however, the direct and indirect costs are significant, due in part to where the fires are occurring. While there is no single comprehensive source on U.S. electric utility expenses around wildfire, it is estimated that the direct wildfire-caused infrastructure losses, liabilities for utility-caused ignitions, insurance, losses in power revenue, and investments in mitigation, infrastructure hardening, enhanced operations, and labor expansions cost $126–$150 billion/year (2025 dollars; Thomas et al., 2017; National Oceanic and Atmospheric Administration [NOAA], 2021; Bayham et al., 2022; Warner et al., 2025; Franklin et al., 2025). Note that utility insurance rates would consider a combination of utility assets, operations, mitigation strategies, and surrounding non-utility high-value resources and assets, and landscape-scale wildfire risks and historical activity. For context, across federal, state, local, industry, and private entities in the United States, wildfires cost $355–$764 billion/year, which includes preparedness actions, suppression efforts, evacuations, direct damage, legal costs, economic and tax base losses, health impacts, long-term recovery, insurance, and research and development (2025 adjusted dollars; Thomas et al., 2017; Borgschulte et al., 2020; Miller et al., 2021; Bayham et al. 2022; Congressional Budget Office, 2022; Crowley et al., 2023; Cotality, 2024; NIFC, 2024; Warner et al., 2025; Franklin et al., 2025).

Although wildfires originating from utility infrastructure cause substantial damage that is often the focal point, hazard encroachment from fires originating from natural or other human causes also leads to damage to electrical infrastructure, transfer path derates (potentially causing curtailment of energy transfer during peak demand conditions), or preemptive de-energization/public safety power shutoff (PSPS) actions. This dual risk, both from and to the utility, creates a complex positive feedback loop that highlights the need for utilities to incorporate best practices, and for utility right-of-way (ROW) adjacent, multi-jurisdictional entities, including federal power agencies, to manage the landscape in a unified, holistic manner that benefits all landowners and stewards. This not only benefits the utility and ratepayers by reducing risk but also has broader, positive impacts on the public, the economy, and the environment.

Table 1. Traditional peak fire season and primary wildfire drivers by region.

U.S. Region	Peak Fire Season(s)	Primary Drivers
Western/Mountain West	July – October	Drought, high temperatures, strong winds (Santa Ana, Diablo), and lightning igniting dry timber and chaparral. The season has been extending later into the fall.
Southwest	April – July	Often a bimodal peak during the defined period, where the first peak occurs in mid-spring and the second in early/mid-summer before the monsoon season begins, driven by warm, dry conditions and high winds.
Southern/Southeast	March – May January – March	*Two annual peaks. Winter/Early Spring:* Driven by dormant, dry surface fuels (grasses, leaf litter) and high winds. Summer: Florida has a small, secondary summer peak driven by lightning.
Great Plains/Midwest	March – May October – December	*Two annual peaks. Spring:* Driven by dry, cured grasslands, high temperatures, and intense winds before new green vegetation emerges. Fall: Driven by the return of dry, windy conditions after deciduous trees drop their leaves.
Northeast	March – May	Driven by dry surface litter (dead leaves, dormant grasses) before the new tree canopy fully emerges, allowing the sun and wind to dry the forest floor. Fires are generally smaller and less intense than in the Western United States.

U.S. Region	Peak Fire Season(s)	Primary Drivers
Alaska	May – July	Long summer days, high temperatures, and lightning igniting vast boreal forests and tundra. Fires are often large and produce heavy smoke.
Hawaii	May – October	Extended periods of drought, high temperatures, and strong leeward/downslope winds that rapidly dry out invasive grasses.
Guam and Micronesia	January – May	Minimal rainfall combined with high temperatures and traditional agricultural practices (like slash-and-burn) often trigger grassland fires.
Puerto Rico and U.S. Virgin Islands	February – May	High solar radiation and the accumulation of dry brush and grass fuels during the main dry season (which typically runs from December to April). Fire activity often drops sharply with the start of the summer rainy season.

Although wildfires are a natural phenomenon and necessary for healthy forest and rangeland systems, the goal is to collectively drive toward higher-frequency, smaller fires at low intensity, rather than frequent, large fires at high intensity (Stephens et al., 2009; Tedim et al., 2020; Stevens et al., 2021; Wu et al., 2023; Kreider et al., 2024). This goal is where the need for collaboration and coordination across multiple entities (federal agencies, state agencies, Tribes, local agencies, private sector organizations, and academia) is crucial, enabling each organization to exercise its full capabilities in its respective stewardship. For example, coordinated controls of vegetation density and structure, surface fuels, and invasive species can be managed to reduce wildfire risk, in addition to finding solutions to significantly reduce all forms of human-caused ignitions, which account for an average of 71 percent of all wildfire starts (Eagleston et al., 2025). It is recognized that for multi-entity coordination to be effective, broader inclusion needs to be incorporated and structured into governance systems that drive partnership programs and collaborative planning and management (Wildland Fire Mitigation and Management Commission, 2023). In response to Executive Order 14308, the U.S. Department of the Interior is establishing the U.S. Wildland Fire Service in 2026 through Secretary's Order 3443, *Elevating and Unifying DOI's Wildland Fire Management Program*, which will align management programs to streamline federal wildfire prevention and response efforts and strengthen interagency coordination.

The objective of this report is to provide an overview of existing and emerging best practices currently employed or planned by utilities for wildfire mitigation, demonstrating how these efforts align with the executive order's emphasis on reducing electric utility–caused wildfires while also balancing cost-effectiveness. Additionally, while most of the practices outlined in utility wildfire mitigation plans (WMPs) focus on risk reduction through robustness and operational reliability, this report also discusses best practices for resilience, as per Executive Order 14239, Achieving Efficiency Through State and Local Preparedness, which includes recovery and long-term system transformation. Utilities that have historically operated in high-wildfire-risk environments, including federal power agencies, mitigate risks in three ways: 1) avoid asset-based ignition and thus impact to areas outside of their ROW corridor, 2) implement multifaceted resilience tactics to withstand or minimize wildfire encroachment and impacts on energy assets, and 3) plan and strategize for timely system restoration to minimize customer outages.

For the purpose of this document, “best practices” are defined as those activities and implementations that have generally been shown to be effective at reducing the risk and effect of wildfire ignition. However, it is important to acknowledge that each utility is distinct in its assets, system configuration, operations, risk interface, risk tolerance, resources, mitigation actions, and preparedness and restoration practices. Furthermore, a utility must define and maintain a constant balance between reliability and safety, considering its risk tolerance and available resources. Finding the right balance requires a deep understanding of local conditions, a willingness to accept more outages for greater safety benefits, and investment in methods and technologies that enhance situational awareness and more nimble system operations and controls. Thus, no single set of practices will produce the same outcomes for every utility. Instead, a curated set of practices needs to be evaluated, adopted, and structured methodically to balance ratepayer and taxpayer investments at an acceptable level of risk for the area in which a utility operates. Wildfire risk is not solely a utility's responsibility; it must be considered across the landscape. Thus, landowners and stewards across local, state, federal, and private entities play a critical role in holistic mitigation and response planning, including fuels management, access roads and fire breaks, evaluation and possible revision to building codes, consequence and interdependency planning, and more. If a risk manifests, the established preparedness and recovery practices are crucial in reducing its impact and minimizing restoration times. Best practices exist at different scales —both temporal and spatial —and encompass physical management, system operations, human factors, and adaptation (Figure 1). For example, spatial scales can vary across efforts: asset health assessments and system hardening at the component-to-circuit scale and forecasted risk assessments at the conductor span to broader system- or regional-level scales, owing to diverse risk profiles driven by geographic location, vegetation, meteorology, and terrain. Risk mitigation, resilience, and reliability actions occur across three temporal phases: pre-event, peri-event (during event), and post-event/recovery (Figure 2). As such, the best practices documented in this report are similarly structured, as the planning and actions for each temporal phase are unique in their implementation. Best practices are drawn from publicly available WMPs in the United States and Canada, recent findings in wildfire risk-reduction research, and industry engagement.

A utility-developed WMP is an important and effective multifaceted tool that strategizes risk mitigation and preparedness. WMPs are broadly categorized into 1) risk assessment and situational awareness, 2) physical and operational mitigation strategies, and 3) stakeholder engagement and regulatory compliance (if it exists). The overarching goals of WMPs are to prioritize public safety by minimizing the risk that their infrastructure assets start or contribute to wildfires. Many utilities are now legally mandated to develop and regularly update these plans. However, utilities that have more mature mitigation efforts understand that the financial and logistical cost of proactively mitigating fire risk is minor compared to the expenses and potential liabilities associated with fighting large wildfires and repairing or rebuilding affected communities. Essentially, investing in wildfire prevention measures is a strategic best practice for utilities to reduce their liability exposure and simultaneously improve their system’s overall safety and reliability.

As of the time of writing, 11 states have passed legislation requiring utilities to prepare WMPs (Barlow et al., 2025a). For example, Texas recently passed House Bill 145, which amends the Texas Utilities Code to address wildfire risk management (Texas House Bill 145, 2025). Many utilities produce WMPs even without state requirements, and instead are motivated by business needs, rate cases, and utility restructuring to limit business risks. To date, 170 of the nation’s utilities (out of nearly 3,000) have publicly available WMPs, with ~75 percent of these plans originating in California, Oregon, and Washington (Abernethy-Cannella, 2025). Notably, the number of utilities with developed plans may be slightly higher, as not all utilities have made their WMPs publicly available. Also, some utilities may have documented procedures for monitoring, assessing, or mitigating wildfire risk that are included as part of a broader hazards management plan, particularly in the Eastern United States.

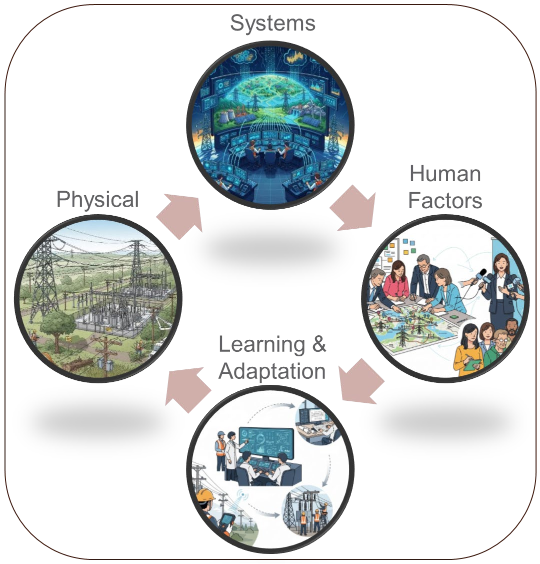

Figure 1. Risk mitigation encompasses physical management, system operations, human factors, and adaptation across multiple spatial and temporal scales.

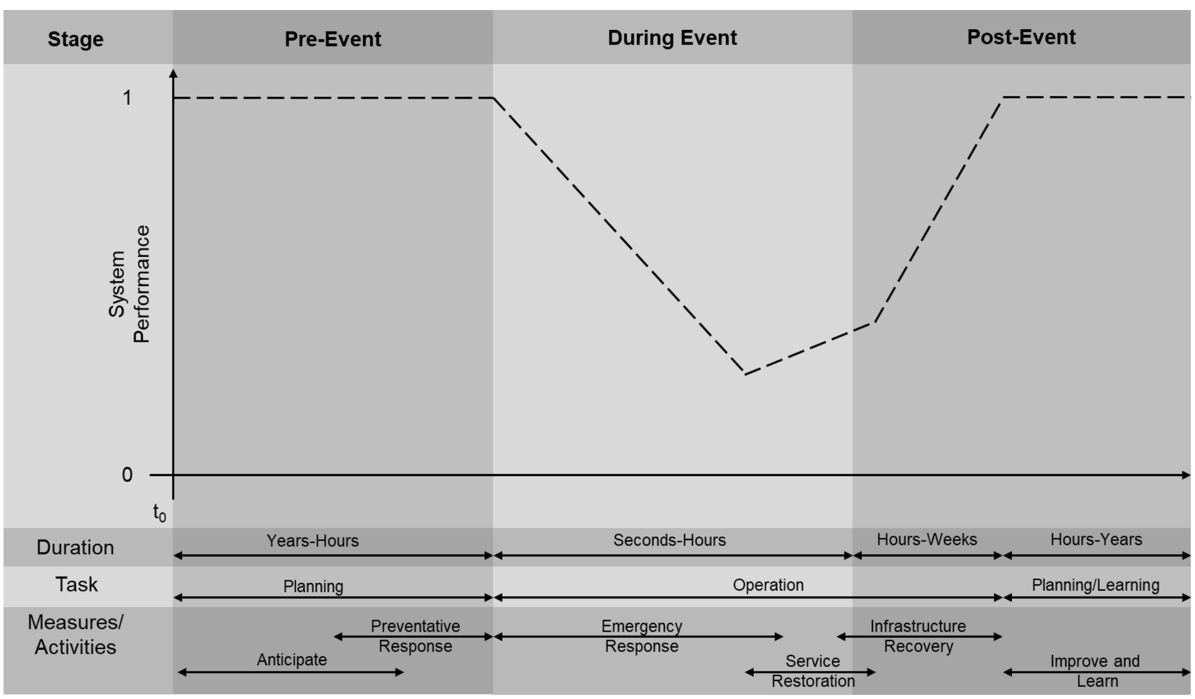

Figure 2. Impact event timeline for risk and resilience mitigation (adapted from Stankovic et al., 2023).

While Executive Order 14308 only references reducing wildfire risk from the bulk-power system, it is important to acknowledge that distribution-level systems are more prone to a greater number of wildfire starts than bulk-power systems. However, transmission-level systems have the potential to cause more catastrophic fires. There are several reasons for this. First, distribution-level conductors are in closer proximity to the ground and often come into contact with laterally adjacent vegetation or undergrowth, thereby increasing the risk of contact. Second, distribution lines occupy a much greater distance (~6 million miles) than transmission lines (~700,000 miles), which alone makes utility-caused ignitions more statistically probable; equipment maintenance and vegetation management are more challenging to accomplish with increased mileage (U.S. Energy Information Administration, 2018; Advanced Research Projects Agency-Energy, 2023; California Public Utility Commission, 2025, Warner et al., 2025). Third, the distribution system has more points of equipment failure along the transmission, with a higher number of components, such as switches, fuses, and pole transformers, all of which can shower sparks upon failure. Conversely, because of the high voltage and greater potential for energy transfer in bulk-power systems, ignitions from downed conductor wire, conductor slap, vegetation fall-in, failed components, or flashovers/arcing are more likely to trigger an ignition. Furthermore, because a bulk-power system traverses a significant amount of remote and rugged terrain, wildfire starts may go undetected for a longer period than they would for a distribution-level system, thus potentially giving the fire time to build strength and momentum. For these reasons, while the focus of the report is on bulk-power systems, the application of best practices to the distribution system is incorporated into this document. For each given best practice, the “System Application” subsection distinguishes whether it only applies to transmission systems or can also be relevant to distribution systems.

Examination of robust national datasets of wildfire ignitions, the Fire Program Analysis fire occurrence database, and NIFC’s InFORM and Wildland Fire Interagency Geospatial Services incident locations reveals that historical wildfires in the United States exhibit high variability in frequency and trends across geographies, with characteristically different behavior in more recent years, including notable increases in ignitions and burn areas throughout the country (Figure 3; NIFC 2025a, 2025b, Short et al., 2022). The complexity of best practices on a spatial scale is further compounded by the varying causes of ignitions and associated damage across the country, many of which are unknown (Figure 4).

This report documents the implementation of these best practices across the utility sector, aligning with the call for enhanced wildfire mitigation strategies outlined in Executive Order 14308. This report provides a comprehensive assessment of the current best practices for risk reduction for utilities and their interactions with wildfire events. This reports adds to and complements other resources that are available, for example, The Institute of Asset Management’s *Contingency Planning and Resiliency Analysis* and *Good Practice Guide for Improving Resilience*, the Western Electricity Coordinating Council’s *Reliability Coordinator Best Practices for Wildfire Impacts and Mitigation*, the 2023 *Report of the Wildland Fire Mitigation and Management Commission*, Stanford University Woods Institute for the Environment *Wildfire: Assessing and Quantifying Risk Exposure and Mitigation Across Western Utilities,* Lawrence Berkeley National Laboratory’s *Bridging the Gap on Data, Metrics, and Analyses for Grid Resilience to Weather Events*, the National Association of Regulatory Utility Commissioners’ *Managing Wildfire Risk in the Electric Utility Sector* and forthcoming *Wildfire Workbook*, Sandia National Laboratory’s *Framework for Wildfire Risk Assessment to Electric Grid*, and the 2025 North American Electric Reliability Corporation’s Wildfire Mitigation Reference Guide (The Institute of Asset Management, 2019, 2025; WECC, 2023; Wildland Fire Mitigation and Management Commission, 2023; Macomber et al., 2024; Collins and Schellenber, 2025; NERC, 2025a; Yusuf et al., 2025).

The following report considers best practices across three phases of a wildfire event, following the resilience curve: pre-event (robustness), during the event (graceful extensibility), and post-event (recovery and long-term change).

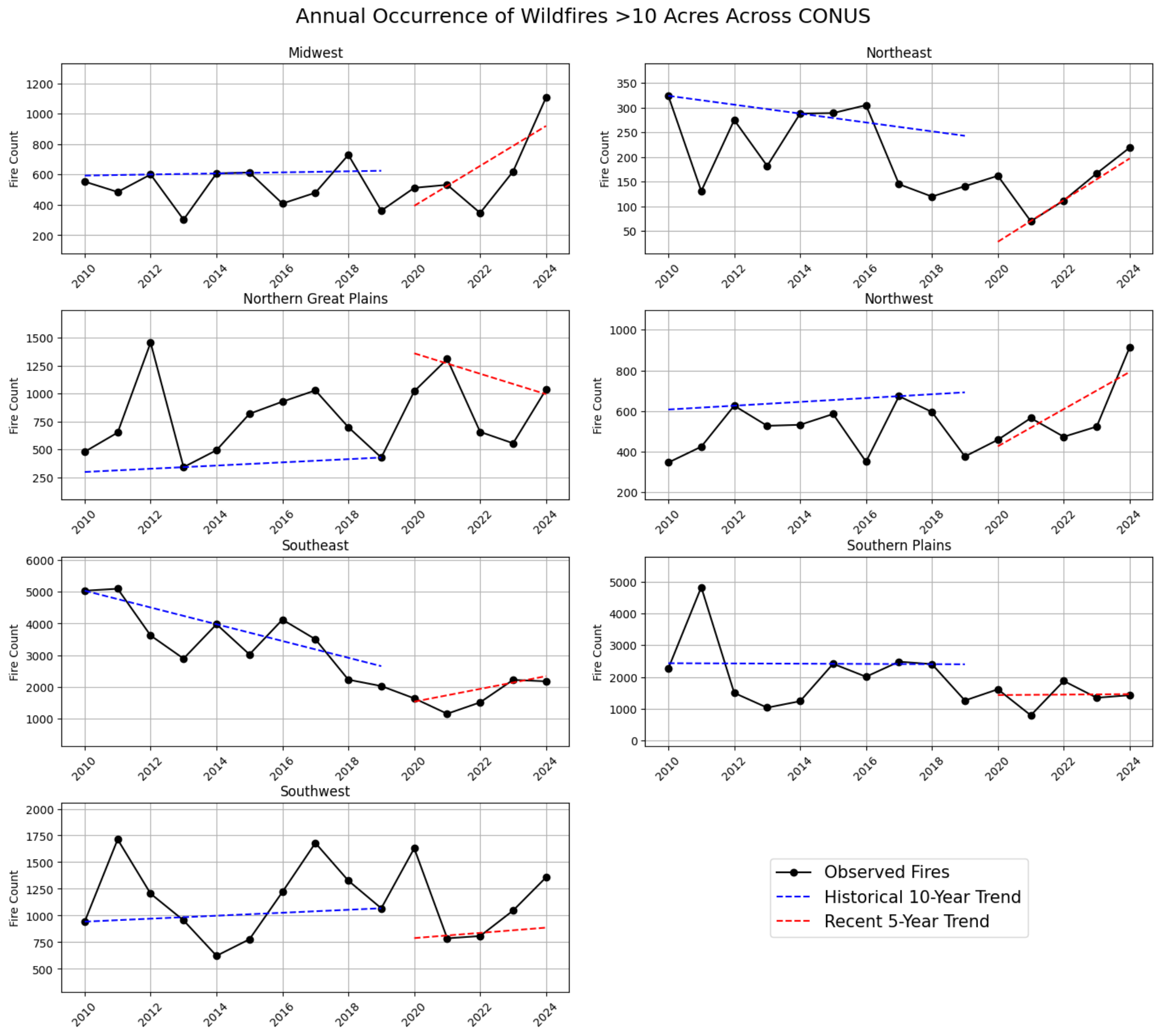

Figure 3. Annual frequency of wildfires at least 10 acres in burn area (black) and associated 10-year trend (2010–2019; blue dashed) and recent 5-year trend (2020–2024; red dashed) over geographic regions of the contiguous United States (underlying data sourced from the InFORM database, NIFC, 2025a).

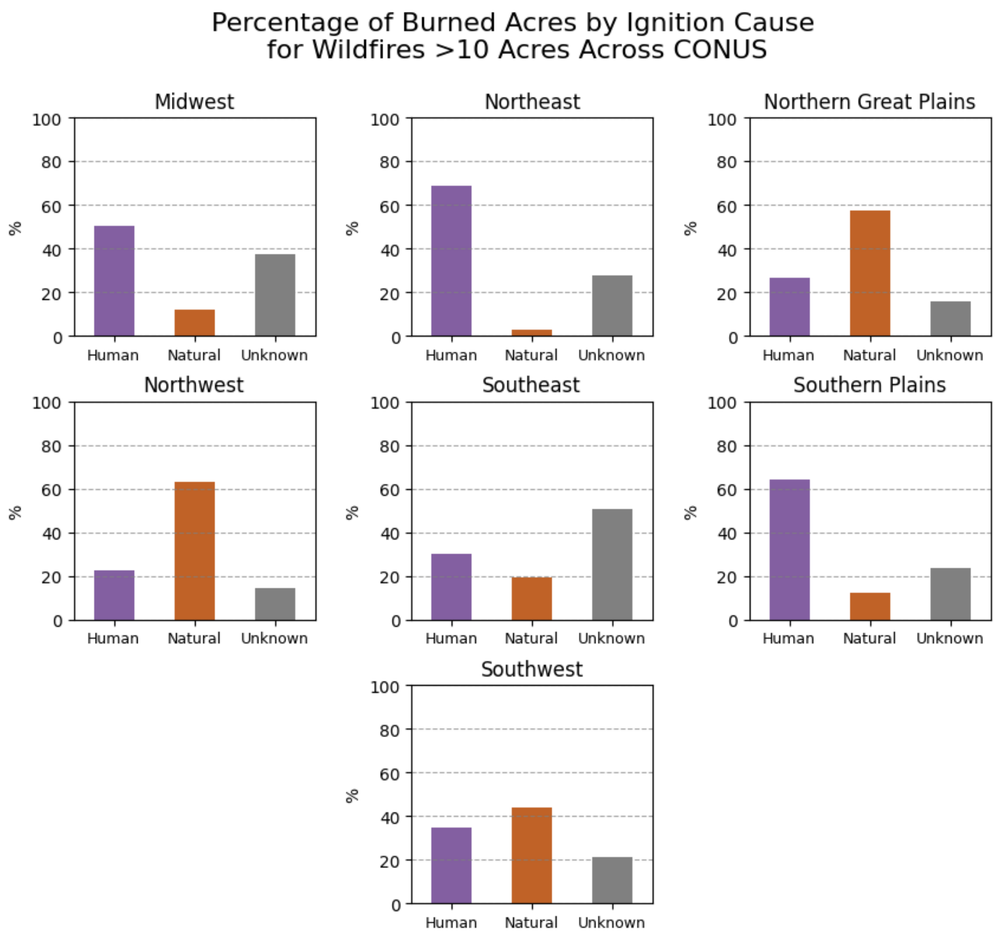

Figure 4. Percentage of area burned by wildfire ignition attribution type over geographic regions of the contiguous United States (2010–2024) (underlying data sourced from Short et al., 2022 and NIFC, 2025b).

The remainder of this report is structured as follows:

Section 2.0 provides a brief overview of utility WMPs, their purpose, their history, and their role with respect to Executive Order 14308.

Section 3.0 focuses on “Resilience as Robustness” or pre-event mitigation efforts, including asset health and management, supply chain and staging, system hardening, engineering designs, risk assessment, vegetation management, and forecasting.

Section 4.0 is focused on “Resilience as Graceful Extensibility” or peri-event practices, including monitoring, adaptive grid operations, Enhanced Powerline Safety Settings (EPSS) or PSPS activation, customer engagement, and mitigation during de-energization.

Section 5.0 provides information on “Resilience as Rebound” or post-event recovery, including system inspections, after-action reporting, post-fire vegetation management, forensics, and adaptations.

Section 6.0 reviews the wildfire regulatory landscape, the utility planning paradigm, the roles of state and federal entities, and current regulatory practices.

Section 7.0 addresses, at a high level, the multifactor cost considerations of implementing utility-focused wildfire mitigations, credit ratings, and liabilities, as well as risk mitigation co-benefits, cost-effectiveness measures, and landscape-level, multi-entity cost-sharing.

Section 8.0 concludes the report with a sampling of current emerging best practices. These include various topic areas of practices that currently have limited evidence of operational application, are being piloted, or are still in the research and development phase.

2.0 Wildfire Mitigation Plans

WMPs serve as living documents that incorporate and drive best practices for utilities that have developed and acted on them. Among the publicly available WMPs, common themes and practices emerge, providing benefits to the entire power systems community (Franklin et al., 2025). As such, it is pertinent to evaluate and document existing strategies to define best practices. Mitigation plans typically have goals to minimize the probability that utility-owned infrastructure will be the origin or contributing source of a fire, ensure public safety, and reduce overall system risk. San Diego Gas & Electric (SDG&E) developed a WMP, with a priority focus on the safety of customers, employees, and the communities they serve. This is achieved through a combination of infrastructure hardening and adaptation, situational awareness, improved weather monitoring and forecasting, and community outreach. Portland General Electric built its WMP on the principles of asset-caused wildfire ignition reduction, incorporation of resilience into infrastructure, community engagement, multi-entity regional collaboration, and data-driven risk-reduction strategies that span vegetation management, infrastructure adaptation, and enhanced controls. Holy Cross Energy (HCE), a utility co-op, built its WMP to "protect public safety and preserve the reliable delivery of power," noting that planning and actions taken in the WMP are "essential to HCE's operational practices" and were done without a state mandate. HCE emphasizes that its WMP is built to address its service territories' unique topography, weather patterns, infrastructure, and grid configuration, and take actions based on the underlying wildfire risk. Federal power agencies also develop WMPs to reduce bulk-power system wildfire risk. The Bonneville Power Administration released its first WMP in 2020, centering its plan on predictive risk assessment, asset health and management, vegetation management, infrastructure hardening and protection, customer and partner engagement, and the development of a PSPS or preemptive de-energization program. More WMPs are being introduced each year, as shown in Figure 5.

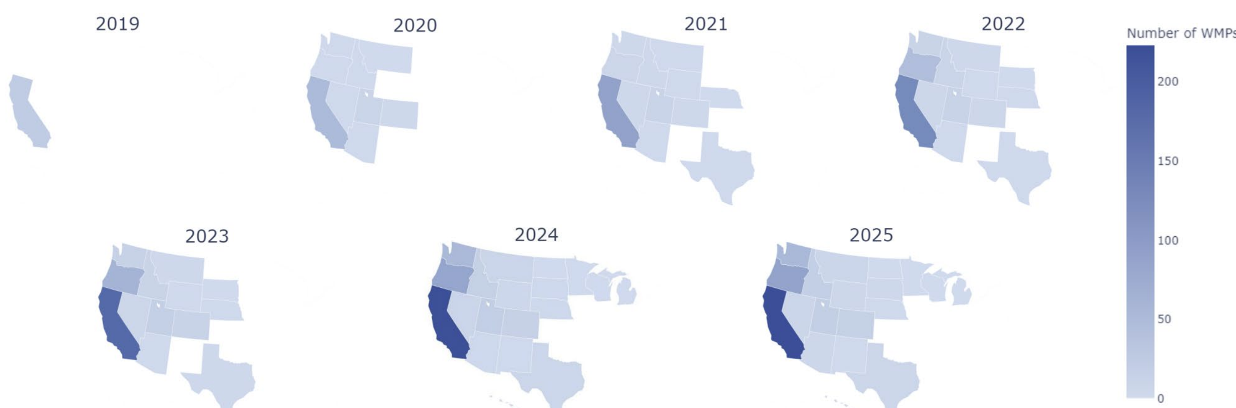

Figure 5. The total number of wildfire mitigation plans (WMPs) in a state in a given implementation year, from 2019 to 2025. The shading in each state represents the cumulative total number of WMPs, including all WMPs for that year and all prior years, dating back to 2019.

WMPs are tailored to unique service areas, their geographic conditions, and their risk profiles. Additionally, WMPs are evolving planning documents with varying levels of maturity. Some utilities employ advanced risk-mitigation capabilities, whereas others remain in a nascent stage. Additionally, there is variation in specific mitigation strategies, technologies, methods of risk assessment, and methods for monitoring and quantifying risk-reduction and protection measures. Most plans emphasize system hardening, vegetation management, inspections, community outreach, and situational awareness. Variations exist in the types of inspections employed and the integration of advanced tools, such as EPSS. Protection schemes are generally not shared, but they differ among utilities because utilities tailor these settings to meet their specific requirements, system design, and operations; refinements are made as experience is gained and as conditions may change. Furthermore, these systems are designed to detect and interrupt faults/broken conductors very quickly. Thus, engineering studies are necessary to coordinate with other schemes to minimize misoperation of protection systems.

To inform best practices, publicly available WMPs were curated from across the United States and Canada. A total of 409 WMPs were curated, representing 170 unique utilities (Abernethy-Cannella, 2025; Franklin et al., 2025). The total number of WMPs represents all discrete WMPs that have been released over time. For example, the Los Angeles Department of Water and Power in California produced five WMPs spanning 2019 to 2025, and the Central Lincoln People's Utility District in Oregon published four annual plans from 2022 to 2025. For utilities that are in the early stages of developing a WMP or are only just recognizing the need for a WMP, evaluating existing plans and analyses available on the Wildfire Mitigation Plans Database, in addition to state-level WMP templates, can help remove barriers to getting started (California Office of Energy Infrastructure Safety, 2020; Washington State Department of Natural Resources, 2024).

The following are key areas of focus within the publicly available WMPs that directly address the provisions of Executive Order 14308:

- **System Hardening and Design Standard Updates:** Utilities are actively involved in improved engineering approaches to enhance grid resilience. These practices include undergrounding power lines in high-fire-risk areas to minimize ignition potential and reduce the need for extensive vegetation management or PSPS actions. Other design modifications involve replacing bare-wire conductors with covered or composite wire, replacing wood poles with ductile iron or steel poles, adding fire-retardant coatings (paints) and fire protective wraps (intumescent mesh) on wood poles, upgrading fiberglass crossarms, increasing overhead wire spacing, using non-expulsion or current-limiting fuses to eliminate potential ignition sources from hot shards, and replacing oil-based circuit reclosers with vacuum-based electronic reclosers. Efforts also include installing animal guards and avian protection. Utilities continuously evaluate new technologies and equipment improvements for wildfire prevention and detection.
- **Vegetation Management:** A primary focus of WMPs and Executive Order 14308 is vegetation management, including regular vegetation maintenance, removal of hazard trees, and the reduction of fuels within the utility and sometimes those adjacent to ROW corridors. Utilities maintain clear ROWs by pruning or clearing vegetation and using herbicides to ensure safe horizontal and vertical distances between vegetation and electrical infrastructure. Some utilities, like Anaheim Public Utilities, collaborate with the City of Anaheim fire departments and other agencies to manage vegetation, using methods such as controlled burns and grazing by goats to clear wild grass in canyon areas. Wasco Electric Cooperative also promotes defensible space around homes and along driveways within its service territory. Similar to WMPs, federal land management agencies (e.g., Bureau of Land Management [BLM] under the Department of the Interior and the U.S. Forest Service [USFS] under the Department of Agriculture) also implement vegetation management policies to manage wildfire fuels adjacent to electric utility line corridors on federal lands.

- **Asset Inventories, Inspections, and Maintenance:** Regular asset inventories and asset health inspections of power lines, poles, crossarms, bolts, insulators, conductor hooks, transformers, and other equipment are critical to proactively identify and address asset-based ignition risks. Traditionally, utilities perform line patrols or otherwise manually walk the lines and visually assess assets in the field. Alternatively, for large service territories, helicopter-based inspections are also used. Newer methods also leverage advanced technologies, such as infrared imaging, lidar, and uncrewed aerial systems (UASs; drones), combined with AI and machine learning (ML) for the detection of problems such as corrosion, damage or reduced integrity, overheating of equipment, and vegetation encroachment.
- **Safer Operational Practices:** Implementing safer operational practices involves enhanced situational awareness, adjustment of system operations during high-risk conditions, and protocols for power shutoffs and system recovery. Some utilities deploy their own weather monitoring stations and high-definition cameras to gather real-time data on wind, temperature, and humidity, enabling continuous monitoring, threshold alerts, and informed critical operational decisions. Both consortia (e.g., the advanced live emergency response technology [ALERT] ALERTWildfire, funded through public and private sources, including state emergency services) and commercial camera solutions have been developed for such monitoring purposes. Safer operational practices include disabling automatic reclosing upon system fault and implementing faster tripping mechanisms during extreme wildfire risk conditions to quickly de-energize circuits in the event of a fault. Utilities also implement no-test-energizing orders following line trips of facilities in high-fire-risk districts until inspections have been conducted. PSPS protocols are generally used as a last resort to prevent ignitions during extreme wildfire risk, with a focus on minimizing customer impact and coordinating with communities. Coordinated rapid response during emergency events is also essential for reducing wildfire impacts.
- **Collaboration and Communication:** Effective wildfire mitigation necessitates close coordination with other utilities, the public, land managers, emergency responders, fire service providers, and local government entities. If warranted by utility service territory conditions, coordination may also involve state and federal government entities, industry, and private landowners. These collaborations include outage planning, power redundancy design, establishing unified communication platforms, assessment and contingency planning of multi-system interdependencies, and engaging in robust community outreach and education efforts to inform the public about wildfire hazards, preparedness, and potential de-energization events. It is critical that these collaboration and communication protocols are built ahead of time and regularly used and improved through utility-only and multi-entity tabletop training exercises. Trusted relationships between utilities, other industries, the community, and local, state, and federal emergency managers are foundational and need to be leveraged on a regular and ongoing basis.
- **Continuous Improvement and Cost Consideration:** WMPs are evolving documents, requiring regular review and updating to incorporate lessons learned, new technologies, and evolving risks. State-level or utility commission regulatory requirements may dictate the update cycle. Utilities aim to provide safe, reliable, and cost-effective electric service, balancing safety investments with cost efficiency through risk buydown. Many WMPs recognize that the cost of mitigation is small compared to the costs of fighting wildfires or rebuilding communities. Investing in wildfire mitigation practices is considered a best practice to reduce liability and increase system reliability and safety.

3.0 Resilience as Robustness (Pre-event)

Robustness efforts are defined as multitemporal (hours, days, months, or years) pre-event activities intended to reduce the likelihood of a wildfire event or reduce the risk associated with a wildfire encroachment event. These best practices can include routine activities, such as asset inventories and inspections, vegetation management, and targeted efforts in asset hardening, system adaptation, migration to grid-enhanced technologies, and the development of situational awareness tools, as well as geographically staging and warehousing replacement equipment. Best practices for robustness can target both short-term preparedness efforts in anticipation of a forecasted event and the longer-term development of emergency response protocols, along with regular training exercises.

3.1 Wildfire Mitigation Plans

Description of Practice: The development of a WMP is regarded as a best practice in the utility industry and, as referenced in Section 2.0, is required by many western U.S. states. The comprehensive document consolidates information and stakeholders to identify key mitigation strategies and efforts to improve the power system. Utilities use the document as an opportunity to assess, evaluate, enhance, and refine their practices in an evolving landscape as new information and technologies emerge. Section 2.0 further describes WMPs and their content.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefit: A WMP is a centralized repository of best practices planned for implementation or currently being implemented by the utility. A WMP acts as an important communication tool with consumers and other stakeholders, making wildfire response and risk-reduction efforts more transparent. Additionally, a WMP can identify key roles in recovery and help utilities address potential emergency response vulnerabilities in advance of future events. Effective implementation of a WMP can, in some cases, reduce the liability of a utility based on state-level legislation (see Sections 6.0 and 7.0).

Challenges of Implementation: Implementing a WMP presents several challenges. First, utilities face resource and funding constraints, which can limit their ability to generate a robust strategy and update the plan regularly. Additionally, utilities that have historically not faced wildfire threats may lack expertise in developing and implementing a WMP. Expertise is also required to prioritize and evaluate different best management practices for risk reduction and cost efficiency. Finally, WMPs require integrating information across diverse stakeholders at the state and federal levels—in particular, national forest offices, state departments of natural resources, and other land stewardship offices and agencies. Gaining state support in locations with relatively few wildfire events could be challenging.

Examples: Section 2.0 highlights key inclusions within existing WMPs. Additionally, an AI-enabled public repository of these WMPs is available to gather information on best practices for implementation (Franklin et al., 2025).

Future Direction: The development and use of WMPs are based on the idea that these documents will evolve and iterate with changing environmental conditions, as well as reflect technological advancements in risk assessment and situational awareness, long-term infrastructure hardening efforts, and the implementation and exercise of finer controls over system operations. Further, performance tracking, evaluation of effectiveness metrics, and lessons learned from previous WMP implementations are likely to be areas of greater focus in future plans. It is expected that, for many years to come, numerous utilities will begin their first WMP, though they will have the distinct advantage of leveraging what others have already learned and developed. Indicative of observed patterns in state legislation over the past few years, the requirement for utilities to develop a WMP is likely going to increase across the U.S.

3.2 Asset Management and Health

Asset management, as a framework, provides organizations with a multifaceted and comprehensive structure for efficiently managing their assets through data-driven strategies, risk management, operational improvement, and enhanced governance (The Institute of Asset Management, 2019; International Organization for Standardization [ISO], 2024a, 2024b). This framework includes setting up and performing comprehensive, centralized asset inventories and integrating work orders requested and completed, inspecting and assessing the reliability, safety, and resilience of the infrastructure assets, evaluating the impact of lost functionality of the assets, and developing contingency plans to aid in timely recovery with backup inventory and rebuild to restore pre-event conditions or laying out plans ahead of time for adaptive rebuilds. Utilities should employ systematic practices and technologies to inventory, monitor, assess, update, and mitigate infrastructure risk. These systematic practices for data collection and asset assessment are crucial for avoiding information silos and, for small utilities, minimizing the risk of institutional knowledge being lost when employees leave.

Core processes in asset management include conducting asset inventories and asset health evaluations to prioritize repairs, performing preventive maintenance, replacing end-of-life equipment, and implementing hardening or enhanced protection measures. This report identifies four approaches for asset management. Asset inventories involve cataloging and mapping assets to enable data-driven monitoring and planning, while asset health and risk evaluations assess the condition and performance of inventoried assets to mitigate future risks and liabilities. Proactive inspections and advanced inspection technologies are the final two opportunities explored. There is significant overlap between these options, but they are listed separately to acknowledge the degree to which asset inventories and asset health assessments are performed, considering the size and complexity of the system. Additionally, the number of departments involved, the development and training of a system and protocol, the availability of staff and resources to support these activities (see Section 7.4), and a given utility's risk tolerance—which may be informed by varying degrees of wildfire risk (see Section 3.9) and wildfire consequence (see Section 3.10) within a service territory—are all relevant factors in determining which best practice should be employed by a given utility.

3.2.1 Asset Inventories

Description of Practice: Asset inventories involve identifying, describing, mapping, and monitoring all electrical infrastructure, including transmission and distribution lines (both overhead and underground), poles, towers, conductors, transformers, switches, relays, resistors, capacitors, arresters, insulators, spacers, substation equipment, communication systems, and other related components. Up-to-date inventories enable utility-scale strategic decision-making, operational efficiency, service reliability, budget forecasting, event forensics, and operational system improvements. In many cases, asset inventories are a regulatory requirement. Numerous types of commercial and open-source software exist to fulfill this role.

This practice typically includes the following actions:

- Collecting data on asset type, model, serial number, location, installation date, service maintenance history, upgrades, inspection dates, condition, and operating history.
- Utilizing geographic information systems (GISs) and supervisory control and data acquisition (SCADA) systems to create comprehensive databases that provide mapping data with backend asset characterization and monitoring.
- Ensuring an office-to-field-to-office workflow management process is in place such that issued work orders are mobilized and fulfilled, as well as asset inspections recorded, thereby providing the asset inventory systems with regular updates that reflect any system changes.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Asset inventories are fundamental for conducting asset-based risk assessments, evaluating overall utility risk, understanding system risks, prioritizing repairs and hardening upgrades, and performing budget planning to improve the safety, performance, and reliability of system operations. When combined with information on underlying hazard risks, consequences, and forecasted conditions, asset data support critical operational decisions, such as listing lines for potential PSPS action, planning for recloser settings, sectionalizing lines, performing enhanced monitoring, or implementing PSPS protocols. Additionally, maintaining a thorough inventory of spare equipment strengthens operational preparedness (see Section 3.4.1).

Challenges of Implementation: For large systems, managing, storing, and analyzing the vast amounts of data required for reliable grid operations may necessitate a robust data architecture, sophisticated data flows, and next-generation knowledge systems. For smaller, less complex systems, a simpler (i.e., spreadsheet-based) but well-structured inventory system can work equally well, provided the document is accessible to others, has edit controls, is version-controlled, and is regularly backed up. In either case, these efforts include establishing clear processes for data quality assurance and quality control, data cleaning, system monitoring, analysis, normalization, and setting threshold criteria for operational actions. Furthermore, providing relevant training and implementing established processes across multiple utility departments, among relevant staff within smaller utilities, and with various contractors, helps to achieve effective utilization and inform internal decisions.

Examples: Many utilities have integrated asset inventories into their WMPs. For example, one objective of Anaheim Public Utilities is to identify utility assets located in fire threat zones. Additionally, Columbia Rural Electric Association and Hawaiian Electric Company use GIS systems and mobile mapping for their asset-tracking and monitoring operations. Pacific Gas and Electric Company (PG&E) integrates a GIS for asset inventory and location, commercial field software for enhanced inspections, and commercial enterprise asset management software for maintenance, repair, and modification. Furthermore, PG&E utilizes an audit process to validate its asset registry. Many utilities note that assets are only added to an asset management system when their condition is deemed unsatisfactory.

Future Direction: Streamlined and integrated asset inventory systems are imperative to ensure currency, accuracy, and effective utilization, providing a preemptive approach for management rather than the historic run-to-failure mindset. An eventual move beyond spreadsheet inventories is likely necessary as more sensors, controls, and data become more commonplace. This could include, for example, the use of integrated GISs, SCADA systems, field-deployment and inspection software, and UAS-based inspections with AI/ML anomaly detection, providing mapping, analysis, alerts, or visualization. Notably, however, the scale of digitization and implementation will depend on the system's size and complexity. Implementing processes that span and integrate staff across utility departments—such as engineering, planning, operations, and field crews—is essential. Line crews that perform repairs or installations are key to updating asset inventories in near real time via mobile devices and intuitive software workflows.

3.2.2 Evaluation of Asset Health and Risk

Description of Practice: Asset health and risk assessment is a data-driven process for understanding the condition, performance, and reliability of utility equipment and components. These assessments are a foundational component of asset management strategies, synthesizing diagnostic and prognostic information to estimate failure likelihood and determine maintenance requirements, thereby avoiding asset failures that could potentially lead to wildfire ignition. Evaluation of asset health provides critical inputs for the risk modeling methodologies that utilities employ to inform preventive maintenance, equipment upgrade prioritization, asset conditioning forecasting, and failure likelihood assessment, thereby avoiding faults. Records of asset health are often integrated into asset inventories, and where SCADA systems exist, they can also provide a time-series record of asset operation. Asset health evaluations draw from inspection results, sensor data, and maintenance records.

Asset health is evaluated to identify any physical damage, asset degradation, or compromised integrity of supporting equipment. Asset health may also encompass asset design life, external exposure, or the likelihood of failure or fault due to vegetation encroachment, clearance violations with other non-utility objects, or the risk of intentional or unintentional physical damage resulting from surrounding land use and access. Utilities with smart grid capabilities may implement asset management and condition-monitoring systems to automatically issue alerts when components operate outside normal ranges. Utilities with smart grid capabilities may implement asset management and condition-monitoring systems to automatically issue alerts when components operate outside normal ranges. Utilities implement different asset health evaluation strategies based on asset type, size, resource access, and grid configuration. However, ISO 55000 and 55001 provide processes, standards, and a framework for asset health and performance management (ISO, 2024a; ISO, 2024b).

Asset inventories, health, and risk evaluations should also explicitly factor in de-energized and decommissioned facilities, which have been evidenced to ignite fires from static charge buildup on parallel energized circuits or through lightning strikes. Verification and possibly action are needed to properly ground lines that are 1) de-energized during PSPS outages, which adds another task and delay to line restoration, and 2) decommissioned systems whose equipment poses risks of attracting lightning and causing ignition to potentially unmaintained vegetation around these inactive systems.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Data-informed replacement and maintenance strategies improve system resilience. By quantifying asset condition and proactively replacing failing components, utilities can minimize the risk of failure. Continual data collection and analysis provide insights that can inform future adjustments and enhancements to wildfire mitigation strategies, fostering a cycle of improvement.

Challenges of Implementation: Collecting and maintaining health assessment data for a geographically distributed system with different components is both cost- and time-prohibitive. While returns can be substantial in the medium and long term, developing, calibrating, and applying methodologies to calculate risk across various asset types is also labor-intensive. Utilities must balance competing priorities with many assets in need of repair, and using asset health data to develop risk-based approaches for prioritization can be challenging.

Examples: Black Hills Energy explicitly supports its wildfire risk mitigation strategies with asset-based risk assessments. PacifiCorp uses an asset health indexing program to prioritize the replacement of high-risk assets. Similarly, United Power bases its efforts for risk analysis on an asset management approach.

Future Direction: Extend beyond ISO 55000 and 55001 to develop and standardize an asset health index to build a more robust and systematic framework. There is a need for an asset health index that combines multimodal observation data, models, and probabilistic risk assessment to support the prioritization of mitigation strategies across assets, encompassing both electrical flow components and supporting infrastructure. As a standard, there should be reasonable or multiple methods for obtaining the required information to support the variety of utility types and operations. The adoption of a range of technologies can complement existing inspection processes to help identify health anomalies.

3.2.3 Proactive Inspections

Description of Practice: Proactive inspections are field-based assessment and diagnostic activities designed to ensure that utility assets and surrounding conditions meet operationally defined minimum clearance specifications and safety standards. Unlike asset health evaluations, which analyze data trends and performance metrics, proactive inspections visually identify physical defects, safety hazards, and vegetation encroachment. Common types of proactive inspections include the following:

- Patrol inspections: Routine visual surveys of overhead systems to identify visual defects, violations, or safety concerns.
- Detailed inspections: Careful visual and diagnostic examinations of individual equipment pieces, where inspectors record visual findings and rate the condition of equipment to identify existing defects, including minor ones.
- Intrusive inspections: Physical testing or sampling, such as wood pole intrusive inspections, to assess structural integrity and decay mechanisms below groundline.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Proactive inspections are an important component of the asset management process and have been demonstrated to reduce overall operating costs through informed decision-making and investment prioritization. They reduce wildfire risk by enabling utilities to visually identify and address potential issues, such as failing or deteriorating infrastructure, vegetation encroachment, or other anomalies. Inspections ensure the safety of both the public and workers while maintaining service reliability. Information gathered from visual inspections enhances overall understanding of environmental and operational conditions, thereby strengthening other components of the WMP, such as operational practices and response strategies.

Challenges of Implementation: The implementation of proactive inspection programs can face challenges, including limitations on capital and human resources to set up and perform regular inspections, problems with data quality and integration owing to human bias, complexities in prioritization of inspection and remediation efforts, and robust quality assurance and quality control processes for outputs. Maintaining consistency among multiple inspection teams can also prove difficult.

Examples: Several utilities highlight their proactive inspection strategies within the WMPs. Arizona Public Service collects and analyzes results from ongoing trend analyses of fire-risk indices to adapt to ecosystem changes. The company conducts comprehensive aerial or climbing inspections and prioritizes tower management maintenance. PG&E incorporates enhanced inspection processes and tools into its routine inspection and maintenance, adopting a risk-informed approach in which higher-risk assets receive more frequent, in-depth visual inspections. They also utilize drone-based and infrared inspections as part of pilot programs.

Future Direction: Utilities are continually working to enhance their proactive inspection programs. Key aspects of future improvements include integrating tools such as remote sensing and multispectral imaging to improve inspection efficiency. Integrating visual inspection data with asset health data will better support decision-making, including inspection frequency and prioritization. Integrating and managing multidimensional, multi-structured data streams is also important for maintaining diverse inspection and maintenance records.

3.2.4 Advanced Inspection Technologies

Description of Practice: Beyond traditional proactive inspection strategies. New technologies are being leveraged to enhance and streamline the inspection of assets.

- Lidar (short for "light detection and ranging") is a remote sensing method used to create three-dimensional representations of target areas and is often used for vegetation management to identify clearances around electrical infrastructure and to assess line sag under specific load and weather conditions.
- Specialized camera equipment is leveraged for infrared and ultraviolet inspections to detect abnormal heating conditions or other issues not visible to the naked eye, particularly with transformers, jumper splices/connections, or substations.
- Inspections conducted with UASs (i.e., drones) provide a top-down or oblique view of assets while complementing other inspections and reducing the risk of undiscovered noncompliant issues. Drones can be equipped with very-high-resolution true-color, infrared, or hyperspectral cameras, lidar, or other sensors. Images collected by UASs can be processed through AI/ML models to aid in anomaly detection.

These practices enable more precise and automated hazard detection, improved situational awareness, and data-driven decision-making.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Advanced inspection techniques leverage high-resolution and multimodal data to detect anomalies not visible to the naked eye. Lidar data can be used to identify potential hazard trees and vegetation clearance issues, thereby augmenting existing inspection activities. When input into vegetation strike models, these data can also help identify areas with high, medium, and low risk, enabling the prioritization of mitigation efforts. Infrared assessments can identify abnormal heating conditions that might not be detectable through visual inspection alone.

Challenges of Implementation: Utilities are still evaluating the effectiveness, reliability, costs, and scalability of these systems under varied environmental conditions, while considering factors such as accuracy, false alarm rates, and whether they are operated in remote areas with limited connectivity and line of sight. Collecting infrared, ultraviolet, or hyperspectral images is a specialized operation and may require operator training or the services of consultants to calibrate, process, analyze, and provide actionable insights from the data. These systems are also only effective at what they can see; thus, in heavily vegetated areas, only the outer, visible vegetation will be collected. LiDAR systems, however, can penetrate signals through tree canopies to build a 3D point cloud of the vegetation structure. Efficient and timely collection of LiDAR data requires an aircraft or UAS, and the associated data post-processing requires a knowledgeable analyst in the space and is time and compute-intensive (i.e., not real-time analysis).

Examples: Multiple utilities have leveraged lidar for vegetation management, including Idaho Power Company and Liberty Utilities. Bear Valley Electric Service uses UAS to collect infrared thermography data to identify “hot” areas indicating deterioration, which are then reviewed by engineers for corrective action and to detect systemic issues. Redding Electric Utility conducts infrared patrols of overhead lines on a five-year cycle and uses UAS for infrared inspection of hard-to-reach areas. SDG&E utilizes helicopters to gather infrared data for enhanced inspections, enabling the identification of hot spots and equipment degradation.

Future Direction: As utilities continue to implement advanced inspection technologies, integrating them into a larger repository and management system can improve coordination, enhance analysis, and enable automation. Integrating multiple technologies allows for comprehensive risk assessment.

3.3 Independent Process and System Evaluation

Description of Practice: An independent process and system evaluation is an in-depth review of a utility’s operations, projects, and assets conducted by a third party with no direct involvement or bias. The goal is to provide an objective, data-driven assessment of a utility’s practices, identify potential weaknesses, and offer recommendations for improvement. The evaluation process typically involves a team of external experts, consultants, or regulators who review a utility’s internal documents, including project plans, risk registers, and operational procedures. They conduct interviews with utility staff at all levels and perform on-site inspections. The evaluation consists of several key components, including 1) a process assessment involving a review of the effectiveness and efficiency of existing processes for things like wildfire mitigation, asset management, and vegetation management, 2) a system and technology review involving evaluation of the utility’s technology stack, from SCADA systems and protective devices to real-time monitoring systems, 3) risk and cost analysis, which involves evaluating the utility’s risk models and cost estimates to ensure that they are robust and align with industry best practices, and 4) compliance and best practices assessment to verify that the utility is meeting or exceeding regulatory requirements and following recognized industry standards.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: An independent evaluation provides an unbiased perspective, a crucial benefit in risk mitigation. Independent audit teams can identify systemic problems or vulnerabilities that internal teams may overlook due to institutional bias or familiarity. This is particularly valuable in high-risk domains, such as wildfire prevention, where even a small oversight can have catastrophic consequences. An independent evaluation adds credibility to a utility's risk mitigation strategy for regulators, investors, insurers, and the public. It can demonstrate a commitment to safety and serve as a powerful tool to justify and secure funding for high-cost projects. Furthermore, evaluations can highlight weaknesses in processes, such as inadequate data collection, outdated risk models, or poor coordination across departments. This enables the utility to address these issues preemptively, preventing them from escalating into incidents.

Challenges of Implementation: Independent evaluations can be challenging to implement effectively. Hiring external consultants and dedicating internal staff time to the evaluation can be expensive. The process is resource-intensive and can be a significant burden for smaller utilities with limited budgets. Some utility employees and departments may be hesitant to be completely transparent with an external team, fearing that the evaluation will be used to assign blame. Building a culture of trust and ensuring a collaborative process is essential for success. The electric grid is a highly complex system with unique characteristics for each utility. An external team may struggle to fully grasp the nuances of a specific grid, leading to recommendations that may be impractical or ill-suited to the utility's challenges. Given this, an opportunity for iterative review, feedback, and adjustment may provide the best outcome.

Examples: Local publicly owned electric utilities and electrical cooperatives in California are subject to a statutory requirement (Public Utility Commission §8387(c)) to employ a qualified independent evaluator to review the comprehensiveness of their WMPs. Publicly available WMPs outside of California do not note the use of independent evaluators. For example, Ukiah Electric Utility is required to contract with an independent evaluator and present the results of the review to the Ukiah Valley fire chief, whose comments are treated as an independent auditor. Southern California Edison Company (SCE) is required to have procedures for conducting independent reviews of data collection and risk models. Additionally, SCE utilizes independent internal data, modeling, and engineering personnel to review inputs and coding used to develop risk-spend efficiencies (RSEs).

Future Direction: The future of independent process and system evaluations will be characterized by greater reliance on multimodal data, automation, enhanced analytical capabilities, and a more integrated, holistic approach. Future evaluations are expected to focus less on manual document review and more on automated data analysis. AI/ML will undoubtedly be used to rapidly process vast amounts of data from SCADA systems, sensors, smart meters, work orders, finances, and more to identify anomalies and performance gaps. Furthermore, instead of single evaluations, there will be a shift toward continuous, or at least more frequent, independent monitoring. This will allow utilities to get real-time feedback and make more rapid adjustments to their risk mitigation strategies. The evaluations will likely move beyond simply assessing processes to focus on outcomes, such as RSEs, reliability, and adapting to changing conditions. For example, instead of just checking whether a utility has a vegetation management plan, the evaluation will use advanced analytics to measure the plan's effectiveness in reducing faults and ignitions.

3.4 Supply Chain Management

3.4.1 Electrical Component Supply Chain

Description of Practice: Supply chain management for electrical components involves ensuring timely availability, current and future sourcing, and current and future pricing. It also entails identifying supply chain risks and staging the geographic distribution of specialized equipment required for risk mitigation activities, including preventive measures, system hardening, and a key part in rapid post-event restoration and recovery. This practice recognizes the potential for long lead times in procurement and proactively purchases and stockpiles components to mitigate the possible constraint on hardening, recovery, and other efforts. Documentation and maintenance of strategic spare equipment are elements of asset inventory management that contribute to recovery actions (see Sections 3.2.1 and 5.1).

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Effective supply chain management directly contributes to wildfire risk reduction by enabling utilities to achieve their hardening and other preventive measures goals as time and resources allow. Ensuring that necessary materials are readily accessible facilitates prompt restoration of electrical service after a wildfire, thereby minimizing outage duration and impact. In some cases, section rebuilds may transition to an improved and adaptive state, facilitating enhanced control and hardening. This proactive approach also supports the overall safety and reliability of the electric system by allowing for the timely deployment of critical equipment and technologies.

Challenges of Implementation: A significant challenge in implementing effective supply chain management for wildfire mitigation is the limited availability of specialty utility equipment, such as distribution power transformers, large power transformers, circuit breakers, switchgear, conductors (both overhead and underground), and utility poles. Utilities are actively facing supply chain constraints due to increased demand related to infrastructure in need of upgrades, raw material shortages, limited domestic manufacturing capacity, and workforce shortages. These constraints directly affect project lead times, increase costs, and increasingly threaten grid reliability and capacity, hindering infrastructure modernization (DOE, 2022a; APPA, 2024; Rohrer, 2024).

Examples: Hawaiian Electric has an isolated island grid, which creates logistic complexity and long lead times. Xcel Energy Public Service Company of Colorado noted that competition for materials is driving a pivot from replacing to repairing equipment.

Future Direction: In response to material shortages and supply chain disruptions, utilities can shift procurement timelines earlier, such as with “year-ahead purchasing,” to facilitate adherence to construction schedules and ensure preparedness. As noted by Rohrer (2024), many equipment manufacturers “are not taking on new customers and are only providing quotes if a procurement mechanism is already in place.” Several electric utility supply chain task force groups and strategies have been developed or are already in place, including the National Conference of State Legislatures Energy Task Force, DOE supply chain strategy, and the Cybersecurity and Infrastructure Security Agency Information and Communications Technology Supply Chain Risk Management Task Force (DOE, 2022b; National Conference of State Legislatures, 2025; Cybersecurity and Infrastructure Security Agency, 2025).

3.4.2 Shared Asset and Technology Database

Description of Practice: A shared database of assets, asset operation, performance, benchmarking, and operational efficiency is a centralized repository and/or consortia that integrates data sources, models, tests, and findings related to electrical grid assets, which can be shared with other utilities, industry groups, and stakeholders to improve awareness and decision-making. The goal of these shared resources is to help utilities understand new technologies, compare performance and failures, identify cost and performance efficiencies, and inform strategic planning.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Ongoing data and practice sharing enable utilities to proactively address wildfire risk through education, review, analysis, strategic planning, and technology piloting. While many of the benefits of information sharing contribute to planning and engineering, they should ultimately expand to finance (strategic investments), operations (enhanced operational capability), and customers (safety and reliability).

Challenges of Implementation: Maintaining an up-to-date, comprehensive list of assets, asset performance, technologies, and associated actionable data can be resource-intensive. Furthermore, with any potential change being considered, additional research, modeling, piloting, and budget planning are necessary prior to deployment. As with any upgrade or change in systems, multi-departmental education and training are required for installation, maintenance, configuration, and operation. Therefore, there are upfront costs associated with these reviews and transitions; however, shared resource databases enable efficiencies, insights, and advancements that would be difficult to achieve independently.

Examples: The Electric Power Research Institute (EPRI) maintains a series of “Industrywide Failure and Performance Database” reports that cover transmission components, substation components, transformers, relays, underground conductor technologies, asset registries, and more. Furthermore, EPRI’s Open Power AI Consortium is focused on developing and sharing a range of power-sector AI solutions with collaborative testing environments and deployment strategies (EPRI, 2025). The National Rural Electric Cooperative Association (2025) hosts the Smart Grids and Data Consortium, which aims to “identify solutions to meet the specific needs of electric co-ops” and “develop repeatable approaches to use digital technologies to modernize grid infrastructure and better serve rural communities” The International Wildfire Risk Mitigation Consortium (2025) provides “ongoing sharing of data, information, technology, and practices, and proactively address the wildfire issues through learning, innovation, analysis, assessment, and collaboration.” At the utility level, the Imperial Irrigation District notes that it shares data with neighboring utilities to better understand the drivers of wildfire risk. Bear Valley Electric Service has created a centralized geographic data repository that digitizes fieldwork activities and automates data flow into a standardized data format defined by the California Office of Energy Infrastructure Safety, enabling simplified sharing with other agencies and utilities. San Francisco Public Utilities Commission electric assets are within the PG&E service area, so PG&E shares its algorithms to enable consistent, validated asset risk modeling.

Future Direction: There is an increasing number of new assets and technological innovations on the market marketed to address wildfire risk mitigation. Deciding which products and systems are effective for wildfire mitigation and asset protection is becoming increasingly confusing and overwhelming for utilities. They require faster access to independent, credible, and actionable information, without paywalls, to make responsible, informed procurement decisions with confidence. Furthermore, at the utility level, data and practice sharing is generally restricted, limiting the efficiency of regional risk assessments, the exchange of practices and experiences, and the coordination of operations. Regional utility consortia could help drive coordination and business efficiencies.

3.4.3 Geographic Distribution of Spares to Reduce Risk/Hazards

Description of Practice: The distribution or dispersal of spare parts, also known as prepositioning equipment, supports quick replacement of individual failed or low-health assets and more timely, larger-scale post-event recovery. The best practice is to have the necessary equipment and specialized components readily available and strategically positioned, thereby reducing hazard vulnerability (i.e., low-health, high-risk assets) and transport times for recovery. The goal is to ensure that stockpiles of assets are not destroyed, allowing utilities to promptly address equipment failures and restore service following wildfire events. This distribution could occur both within a utility's service area or through coordination with neighboring utilities.

By enabling faster, more effective response, the distribution of spares significantly affects both distribution and transmission lines that may require repair during and following a wildfire event. Spare parts can include high-voltage conductors, insulators, and replacement transmission poles and tower components. Pre-positioned equipment can also include transformers, poles, and fuses for restoring distribution lines.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Dispersal of assets and spares is a common risk-reduction strategy for any hazard type. It removes a single geographical location as a point of failure and enhances readiness and recovery efforts by placing critical components closer to areas of need. This best practice can better support communities by minimizing service interruptions.

Challenges of Implementation: Some equipment, as noted in Section 3.4.1, may have long lead times for procurement, which could limit the amount of equipment and number of dispersal sites involved, particularly as resource inventories are used. Additionally, managing, maintaining, and coordinating multiple sites and their stockpiles poses challenges, including higher costs and the need for a larger workforce. Nevertheless, its outcomes align with those in Section 3.2.1, ensuring an asset management system is exercised and updated. Coordination of materials relies on standardized assets and system compatibility.

Examples: SCE incorporates prepositioning strategies for equipment and employees into its emergency preparedness plans for service restoration. Black Hills Energy gathers supplies and equipment in anticipation of restoration operations once wildfire risk has lifted. Arizona Public Service, like many other utilities, maintains mutual assistance agreements with other utilities (namely Western Energy Institute and Edison Electric Institute) that involve augmenting the workforce and/or equipment upon request.

Future Direction: Utilities can prioritize stockpiling spares for high-risk components that are prone to damage or destruction during wildfires, such as conductors, transformers, relays, reclosers, and wooden poles. If components are upgraded with fire-resistant alternatives, spares of the newer equipment are also important to distribute. Utilizing risk assessment models in conjunction with utility properties and maintenance yards can help pinpoint the best locations for distributing spares. Additionally, if not already in place, proactively developing mutual assistance agreements and neighboring utility agreements would facilitate the pooling of staff and equipment resources for wildfire or other hazard events. Such mutual assistance programs are common and have existed for investor-owned electric utilities, such as the one from the Edison Electric Institute. The Edison Electric Institute has expanded its program to form a regional-level mutual assistance group (DOE, 2023).

3.5 System Hardening

3.5.1 Undergrounding

Description of Practice: Undergrounding involves reconfiguring portions of an electrical distribution or transmission system from overhead to underground. This involves trenching or tunneling, installing conductors in conduit, and installing other equipment in vaults (e.g., splicing vaults). This is generally a targeted process that accounts for both 1) susceptibility to faults, outage, or wildfire ignition and 2) the number of customers served. Undergrounding can be executed through new construction or converting existing overhead lines to underground systems.

System Application: Can be applied to transmission systems but is more commonly used on distribution lines.

Risk Mitigation Benefits: In addition to significantly reducing wildfire risk, undergrounding offers other benefits, including nearly or fully eliminating the risk of ignition from power lines by protecting them from aboveground hazards such as wind, lightning, fire, or animal contact. Additionally, undergrounding lines reduces or eliminates the need for PSPS events, improves reliability and resilience, and reduces or eliminates vegetation management requirements.

Challenges of Implementation: Despite its benefits, undergrounding presents several challenges. Chiefly, undergrounding is generally the costliest system hardening option on a per-mile basis, typically 3- to 10-times more expensive than overhead construction or covered conductor installations. Costs can vary significantly depending on factors such as terrain, bedrock, permitting, easements, environmental sensitivities, urban versus rural areas, and existing underground structures. Undergrounding projects are also engineering-, design-, and construction-intensive, taking significantly longer to implement than other mitigation measures, often 1.5–5 years from concept to completion. Challenging or rocky terrain, steep slopes, groundwater, and varying soil conditions can make undergrounding impractical or infeasible. Additionally, the conditions may be such that other hazards (e.g., landslide potential, frequent flooding, or frequent earthquakes) present their own risks that make undergrounding less viable. While relatively uncommon, underground outages can be more complex, challenging, and costly to locate and repair, leading to longer restoration times than overhead outages. Furthermore, there is evidence that underground lines have a shorter lifetime because of excessive heat buildup and increased exposure to moisture. Undergrounding for transmission lines is often not practical due to cost and physics-based constraints (i.e., heat dissipation, large capacitive charging current for AC systems limiting span distances), and is saved for the most extreme circumstances where short spans can be run.

Examples: Undergrounding of lines is a common best practice across WMPs. SDG&E implements a strategic undergrounding program that includes areas within defined high-fire-risk districts and other areas with a high prevalence of PSPS events, high-risk wind conditions, or other hazards. Lane Electric Cooperative is actively and aggressively moving primary overhead lines underground, having already undergrounded nearly half of its 1,178 miles of line. Cowlitz Public Utility District (PUD) No. 1 has approximately 1,321 miles of underground distribution line on its network and is prioritizing future undergrounding projects in high-fire-risk areas. SCE has over 7,400 circuit miles undergrounded (SCE, 2025), and PG&E plans to underground approximately 1,600 miles of primary and secondary powerlines by 2026 (PG&E, 2025c). PacifiCorp, Bear Valley Electric Service, and other utilities recognize undergrounding as an effective wildfire mitigation strategy but find the costs, operational constraints, and timelines to be prohibitive. Xcel Energy notes challenges in undergrounding due to “onerous permitting requirements” from various state and federal agencies. Horizon West Transmission undergrounded its only transmission line to address high wildfire risk in the area and the lack of other effective alternatives.

Future Direction: Utilities will continue to refine their undergrounding strategies, specifically evaluating cost-effectiveness, RSE, multi-attribute value functions (MAVFs), and the value of benefits beyond cost. The use of advanced risk models will continue to inform undergrounding decisions, considering factors beyond ignition risk, including PSPS impacts, ingress/egress, and environmental factors.

3.5.2 Covered Conductors/Reconductoring

Description of Practice: Covered conductors, also known as tree wire, are electric power lines that are covered by multiple layers of insulation. These layers are designed to allow the wires to withstand incidental contact with vegetation or other debris, differentiating them from traditional bare-wire conductors. The construction typically involves high-impact resistant extruded layers forming insulation around a stranded conductor. For example, SCE utilizes a robust three-layer design, and SDG&E specifies triple extruded layers with a semi-conducting sheath, an insulating polyethylene sheath, and an abrasion-resistant cross-linked polyethylene (XLPE) external cover.

System Application: Can be applied to transmission systems (particularly for lower voltage transmission), but is traditionally applied to distribution systems.

Risk Mitigation Benefits: Covered conductors offer substantial benefits in terms of reducing wildfire risk and enhancing system reliability and are effective at mitigating ignitions caused by contact with foreign bodies, typically vegetation, or wire-to-wire contact (DOE, 2024). The multilayered polymeric insulating sheath reduces vulnerability to arcing and faults, which can lead to wildfires, thereby reducing outages, improving reliability, and reducing the need for PSPS activation. This includes protection from tree/vegetation contact, wind-induced contact, third-party damage, animal-related damage, and moisture. Compared with bare conductors, covered conductors have the potential to raise the wind speed threshold for PSPS events. Utilities estimate that covered conductors can reduce drivers of wildfire ignition risk by approximately 60-90 percent.

Challenges of Implementation: While the use of covered conductors is often more economical than full undergrounding, deployment costs vary significantly depending on factors such as system design, required structural and equipment replacements, topography, scale of deployment, and resource availability. Covered conductors introduce unique failure modes that require operators to consider additional personnel training, enhanced installation practices, and the adoption of new mitigation strategies (e.g., additional lightning arresters or conductor washing programs). Some of these new failure modes could increase risk or reduce the effectiveness of the insulating sheath if not properly addressed. There is a noted lack of specific literature on issues such as sheath damage/flammability from encroaching fire, heat, and smoke particulate contamination, moisture ingress, and covered-conductor sway behavior affecting poles. Utilities face potential challenges during implementation, including skilled labor resource constraints, supply chain disruptions, and unanticipated events. Some sources indicate that field data for measuring long-term effectiveness is limited, leading utilities to collaborate on developing consistent methodologies. For instance, SDG&E noted that as of late 2021, PSPS thresholds had not yet been raised on any circuits that had been fully hardened with covered conductors due to the limited time that had passed since installation.

Examples: Many utilities are actively implementing or evaluating covered conductor programs. PacifiCorp recognizes covered conductors as an industry best practice and installs insulated covered conductors for most projects in its Line Rebuild Program within fire hazard areas and high-fire-risk districts. SCE considers covered conductor deployment a primary wildfire mitigation activity, aiming to harden the majority of its overhead distribution system in high-fire-risk areas, and they utilize a robust three-layer design. By the end of 2021, SCE had installed approximately 2,500 circuit miles of covered conductors, with plans to reach over 7,200 miles (approximately 75 percent of distribution primary overhead conductors in high-fire-risk areas (HFRA) by the end of 2025. SDG&E specifies the use of triple extruded layers, consisting of a semi-conducting sheath, an insulating polyethylene sheath, and an abrasion-resistant cross-linked polyethylene (XLPE) external cover. Hawaiian Electric Company is actively pursuing the use of covered conductors as a wildfire safety strategy, developing installation standards, particularly for circuits operating at or below 15 kV. Portland General Electric and Puget Sound Energy reported on significant and continued installation of covered conductors and spacer cables, and Portland General Electric specifically noted the coupled transition to covered conductors with the installation of ductile iron poles to achieve fire-safe construction standards.

Future Direction: Utilities are continually working to enhance their understanding and application of covered conductor technology. Future efforts include obtaining new test data, conducting further benchmarking, improving methods for estimating and measuring effectiveness, and furthering alternative assessments and unit cost comparisons. Efforts are necessary to analyze installation practices, identify any additional inspection and maintenance requirements, and develop best practices for inspecting and maintaining covered conductors.

3.5.3 Advanced Conductors/Reconductoring

Description of Practice: Advanced conductors are a next-generation technology for modernizing electric grids. They are a significant upgrade from traditional conductors, which often use a steel core with aluminum strands. In advanced conductors, the heavy steel core is typically replaced with a lighter, stronger, and more thermally stable material, such as a carbon-fiber composite. This allows more aluminum to be packed into a cable of similar diameter, enabling the conductors to carry more current (increased capacity) with less sag and energy loss.

The primary practice for deploying advanced conductors is reconductoring, which involves replacing existing wires on distribution and transmission towers without building new towers or acquiring new ROWs. Because new transmission lines can take a decade or more to permit and build, reconductoring offers a much faster and more cost-effective way to increase grid capacity. This process is particularly useful for aging infrastructure and for connecting new energy sources to population centers or other areas with high energy demand (e.g., manufacturing areas or data centers). The primary practice for deploying advanced conductors is reconductoring, which involves replacing existing wires on distribution and transmission towers without building new towers or acquiring new ROWs. Because new transmission lines, in particular, can take a decade or more to permit and build, reconductoring offers a much faster and more cost-effective way to increase grid capacity. This process is particularly useful for aging infrastructure and for connecting new energy sources to population centers or other areas with high energy demand (e.g., manufacturing areas or data centers).

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Advanced conductors offer several crucial benefits for risk mitigation, especially amid increasing hazard stress and energy demands. First, these conductors can carry two to four times more power than traditional conductors of the same size. This higher capacity reduces the risk of thermal overload and grid congestion, which can lead to outages and system instability during peak demand or extreme heat events. Furthermore, increasing line capacity may reduce the number of new builds, in turn leading to fewer corridors to maintain and operate. Second, advanced conductors have a lower coefficient of thermal expansion, meaning they sag significantly less than traditional conductors when under thermal stress. This reduction in the risk of lines sagging decreases the likelihood of vegetation line contact, a major cause of wildfires. Finally, the lower electrical resistance of advanced conductors means that less energy is lost as heat during transmission, resulting in a more efficient system

Challenges of Implementation: Despite the clear benefits of advanced conductors, several challenges hinder their widespread adoption. The first is higher upfront costs due to the higher material costs of advanced conductors compared to traditional conductors. While this cost is often offset by the long-term benefits and the lack of need for expensive new construction, it can be a barrier for utilities operating on limited budgets or those without a regulatory framework that incentivizes these capital expenditures. Second, some advanced conductors require specialized tools and trained crews for installation due to their composite cores. This can create a learning curve and require a short-term investment in workforce development, further increasing upfront costs. Finally, in some jurisdictions, regulatory structures incentivize the development of new, large-scale projects over smaller, more efficient upgrades. This structure can create inequalities for smaller utilities, often where system hardening measures are most needed. Furthermore, with every new technology, there can also be a lack of awareness among regulators and utility leaders about the full potential of advanced conductors.

Examples: Many utilities, particularly those in high-fire-risk areas, are evaluating, piloting, or adopting reconductoring approaches; however, the vast majority of these are covered conductors. Hawaiian Electric Company is evaluating advanced reconductoring approaches that use modern composite and/or carbon cores to achieve a 1.5-times increase in capacity over existing equipment. Similarly, SCE faces dual challenges of population growth and high wildfire risk and has embraced advanced conductors. SCE has completed dozens of aluminum-conductor composite-core installations to upgrade aging infrastructure, boost capacity, and reduce line sag, thereby mitigating fire risk. NV Energy has completed numerous aluminum-conductor composite-core installations. However, its primary goals are to upgrade critical transmission lines and accommodate the growing energy demand from new data centers.

Future Direction: The adoption of advanced conductors is expected to increase and become more widespread, with ongoing efforts to overcome implementation barriers and establish the technology as a standard for grid upgrades. Federal and state policies are increasingly encouraging the use of advanced conductors by offering grants and requiring utilities to consider them in their long-term planning. This shift from a “least cost” to a “maximum net benefits” approach will drive greater adoption. There is an evolving maturity in technology, and manufacturers are developing conductors that are easier to install, with some designs being fully compatible with existing aluminum conductor steel reinforced (ASCR) tools and techniques. Integrating smart monitoring technology into the conductors is another area of development, enabling real-time data on conductor conditions. Finally, as more advanced conductors are deployed, industry-wide standards for their use and components such as connectors will continue to be developed, helping lower costs and reduce uncertainty for utilities.

3.5.4 Reinforcement of Poles and Structures

Description of Practice: Pole and structure reinforcement or replacement involves using various design and construction strategies to enhance the integrity of electrical infrastructure. Utilities may consider using taller structures to reduce the risk of wires contacting vegetation, higher-class poles with larger diameters to increase resilience, and alternatives to wood poles, such as steel, ductile iron, or concrete. With the replacement of poles, overhead wire spacing can also be increased both vertically and horizontally, reducing wire-to-wire contact in high winds. Some utilities also apply fire-retardant paint or pole wraps to wood poles to enhance fire protection and prevent the need for pole replacement. Compared with replacing a burned pole, applying fire-retardant methods to a pole reduces costs by threefold. Additionally, regularly inspecting guy wires for corrosion, wear, or displacement helps reduce the risk of wildfire ignition by preventing poles from leaning or falling.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Replacing or reinforcing deteriorating poles, especially when detected early, reduces the likelihood of ignition. Pole replacements and reinforcements also help minimize the risk of system faults caused by structural pole failure. Steel and ductile iron are suitable candidates for pole construction due to their high fire resistance and strength in high-wind events. Compared with bare conductor hardening, system hardening, including pole and structure reinforcement, could raise the wind speed threshold for PSPS events.

Challenges of Implementation: Utilities face risks during implementation, including capital expenses, skilled labor constraints, and supply chain disruptions related to materials procurement. The speed of installation can be constrained by permitting and compliance reviews, system outage planning, and acceptable time periods for installation.

Examples: Avista and Bonneville Power Administration have implemented a transmission fire-retardant program, transitioning from retardant paints to a fire-mesh wrap with an expected 20-year life for transmission wood poles. Benton PUD includes steel pole conversion as part of its preventive programs. PacifiCorp continues preemptively treating poles with fireproofing spray in targeted Tier 3 and Tier 2 areas and is implementing a five-year plan to proactively replace wooden poles with steel structures. In 2020, PacifiCorp proposed an accelerated replacement/reinforcement of approximately 4,000 poles.

Future Direction: There are several options for reinforcing or replacing vulnerable poles and structures, each with varying implementation costs. Utilities can explore alternative pole materials that are less vulnerable to wildfire or utilize fire-retardant wraps and paints. Targeting infrastructure in high-fire-risk districts offers the greatest opportunity for impact.

3.5.5 Lightning Arresters and Shield Wires

Description of Practice: Lightning arresters, or surge arresters, are electronic devices installed in power systems to divert high-energy surges from lightning currents safely to the ground to minimize the risk of a catastrophic thermal runway. The goal of this strategy is to mitigate the impact of transient overvoltage on the electric system, thereby protecting equipment and reducing the prevalence of fire-starting faults. Lightning arresters can have advanced features such as arc protection systems or spark prevention units. Older arresters are made from porcelain or glass, whereas modern arresters are typically made of fire-safe polymer materials.

Lightning arresters are commonly installed on distribution lines, including overhead-to-underground transitions, with secondary arresters sometimes installed at customer meters. Lightning arresters are generally not installed on transmission lines. Instead, for transmission lines, utilities use shield wires above the high-voltage conductors to mitigate damage from lightning.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Arresters are often installed in power systems alongside other hardening initiatives, such as fire-resistant poles (paints or wraps), to prevent direct line or structure strikes that could result in flashover, wood-pole ignition, conductor damage, or ground-wire damage. This mitigates service interruptions and loss of meters when coupled with secondary arresters, improving reliability and enhancing system safety. For areas with high fire risk, the design and placement of lightning arresters are critical. Utilities are increasingly using distribution arrester systems specifically designed for wildfire mitigation. These systems are built to withstand high-energy surges and minimize the risk of a catastrophic thermal runway, which is key to preventing fire ignition.

Challenges of Implementation: Some arresters have openings that have been used by wildlife for food storage, which reduces the effectiveness of the arrester. Older lightning arresters made of porcelain or glass are at a higher risk of exploding during operation, and these explosions can ignite dry fuel sources. However, upgrading arresters can be costly. Additionally, lightning arresters are electrical equipment that can be thermally overloaded during high-duration or high-energy overvoltage scenarios, potentially becoming an ignition source.

Examples: At the end of life, an arrester will fault to ground and become disconnected from the ground, potentially expelling hot material and igniting flammable vegetation. However, advancements such as non-expulsion upgrades can reduce the emission of hot material during operations. Many utilities (e.g., Columbia Rural Electric Association and Idaho Power Company) are replacing old porcelain arresters that are susceptible to failure. Pacific County PUD No. 2 transitioned to polymer arresters on overhead-to-underground primary taps throughout the distribution system to mitigate ignition risks. SDG&E implemented the California Department of Forestry and Fire Protection (CAL FIRE) exempt lightning arresters, which yield an estimated 80 percent reduction in ignitions. Utilities are increasingly using distribution arrester systems specifically designed for wildfire mitigation. These systems are built to withstand high-energy surges and minimize the risk of a catastrophic thermal runway, which is key in preventing fire ignition.

Future Direction: Arresters with entry points to energized parts should either be equipped with protective arrester covers or replaced with concealed versions to mitigate wildlife interference. If there are opportunities for upgrades, replacing older lightning arresters made of materials like porcelain or glass with polymer arresters will mitigate utility-caused ignition risk.

3.5.6 Wildlife Guards

Description of Practice: Wildlife guards, also referred to as animal guards or avian diversion equipment, are physical covers or devices installed on overhead electrical equipment and lines to minimize contact between wildlife and electrical equipment. These components are often integrated into modified construction standards, becoming a fundamental part of system hardening efforts. Related practices also include installing avian perch poles in active nesting areas to divert birds away from power infrastructure.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: The primary benefit of wildlife guards is minimizing the risk of faulting or arcing of electrical lines and equipment by preventing direct contact between wildlife (including birds) and energized components. This directly reduces the likelihood of an ignition event originating from utility assets.

Challenges of Implementation: A nominal cost is associated with installing wildlife guards. However, this practice has largely been incorporated into construction standards, so the need would primarily be to upgrade legacy infrastructure.

Examples: Arizona Public Service installed phase covers, vice top covers, wildlife discs, arrester and bushing covers, flight diverters, and anti-perch caps on distribution and transmission lines, noting that covers have also minimized incidents involving vegetation or mylar balloons. Chelan County PUD identified problem locations and retrofitted power equipment with animal guards, installing approximately 4,300 to date. Mason County PUD No. 3 has strategically deployed wildlife guards to reduce the risk of ignition through animal contact. However, they generally avoid installing guards in all new constructions due to the risks of moisture accumulation and tracking in their wet climate, reserving their use instead for strategic applications.

Future Direction: Given the few implementation challenges, installing or upgrading wildlife guards in areas with wildlife exposure can mitigate risks. Utilities can prioritize installations based on knowledge of animal activity and outages, and consider material degradation timelines to ensure product effectiveness. Advanced monitoring systems, such as drones, can assist in remote areas.

3.6 Engineering Design and Implementation

3.6.1 Sectionalizing and Islanding

Description of Practice: Sectionalizing refers to strategies that involve isolating or de-energizing specific portions of the electrical distribution system to prevent or minimize wildfire ignitions and sustain system operations when existing wildfires threaten transmission lines, thereby reducing customer impact. These strategies often include disabling automatic reclosers to prevent repeated energization of a line that could cause an ignition (NERC, 2021). Islanding is the practice of operating a portion of the grid independently of the main utility grid, typically as a microgrid. When parts of the system are disconnected from transmission lines, a local area can leverage distributed generation to maintain services to critical facilities and customers.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Both sectionalizing and islanding offer significant wildfire risk mitigation benefits, including minimizing ignition sources, limiting wildfire spread, and enhancing overall grid reliability and resilience. Additionally, these efforts can be designed to prioritize critical loads, such as emergency services, hospitals, and other critical facilities, to ensure service continuity. Furthermore, sectionalizing and islanding processes can also complement PSPS programs in minimizing customer outages.

Challenges of Implementation: The operational decision-making is often distinct between transmission and distribution operators, and implementing dynamic reconfiguration and islanding requires complex models and a detailed understanding of local system configurations. There are inherent risks of wildfire ignition when sectionalizing, islanding, or reconfiguring the topology. Specifically, switching transients can cause temporary overvoltages that stress power system components, induce insulation failure, and lead to arcing. With the implementation of sectionalizing or islanding with preemptive de-energization, any power shutoffs to customers can affect service reliability and must be balanced against other risks.

Examples: Arizona Public Service leverages advanced grid technologies (AGTs) for sectionalizing to reduce critical loads affected by system faults in high-fire-risk areas. Black Hills Energy uses isolation devices, such as fuses, breakers, and reclosers, throughout its electric system to identify system abnormalities and isolate (de-energize) problem areas, reducing the overall impact on customers. Idaho Power Company actively utilizes feeder segmentation to isolate sections (or segments) of its transmission and distribution system, primarily through the installation of remotely controlled devices, such as automatic reclosing devices (reclosers). Idaho Power Company installed 8 automatic reclosers in Tier 3 Zones in 2023 and planned to install approximately 25 more throughout its service area in 2024. Central Lincoln PUD looped three-quarters of its transmission lines to allow alternative routing and islanding.

Future Direction: Distributed energy resources, such as battery or flywheel storage systems, microturbines, or mobile generators, can be used for sectionalizing and islanding strategies. Additionally, microgrid boundaries can be made dynamic. More sophisticated options include advanced sensors, smart switches, and automation capabilities.

3.6.2 Protective Equipment, Device Settings, and Fast-Trip Systems

Description of Practice: Grid protective equipment and fast-trip systems are crucial for preventing wildfires by de-energizing a line very quickly when a fault occurs, thereby minimizing the risk of ignition. This is achieved through the use of more sensitive settings on devices like circuit breakers, reclosers, and switches, which have historically been set to tolerate a fault for a longer period. The practice involves adjusting the settings on protective devices to make them more sensitive and faster-acting, especially in high-fire-risk areas. This can be done dynamically, by activating these settings during periods of high fire risk, such as a National Weather Service (NWS)-issued red flag warning (RFW), or according to utility-defined risk thresholds or year-round. The following are three common practices:

- Sensitive Ground Fault Detection: Utilities are using more sensitive settings on ground fault relays to detect low-current faults that might not be picked up by traditional protection schemes but are still capable of causing ignitions.
- Fast-Trip Settings: These settings enable a faster and more sensitive protection curve, allowing a circuit breaker or recloser to trip within a few cycles (typically around 100 milliseconds or less), rather than in the standard time frame. This rapid response prevents prolonged arcing that could ignite dry vegetation.
- No Reclose Setting: This setting disables the automatic reclosing function of a device upon a fault. While reclosing is typically used to restore power quickly after a transient fault (such as when a tree branch briefly touches a line), in a high-fire-risk area, it can re-energize a line and create a persistent arc, potentially leading to ignition. Note: Adaptive reclosers are discussed in more detail in Section 3.6.3.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: The primary benefit of implementing grid protective equipment and settings is providing system-level controls to reduce the risk of utility-ignited wildfires. By reducing fault-clearing times and enabling fast-trip settings, the arc energy expended during a fault event is minimized, thereby reducing the risk of ignition from vegetation or other foreign objects. Furthermore, devices and device settings can quickly isolate the problem area, limiting the extent of the power outage. Overall, this is a proactive strategy that can reduce the need for more drastic actions like PSPS, which can have widespread negative impacts.

Challenges of Implementation: Grid-protective equipment comes with trade-offs. First, older mechanical or electromechanical relays are likely to be incompatible with new, sensitive settings, necessitating expensive equipment upgrades. Second, fast-acting systems must be carefully designed and coordinated with other protective devices on the line, such as fuses, to ensure they do not trip out of sequence and cause an even larger outage. Third, the higher sensitivity of the protective settings means that they will trip more often and without notice, even for minor events that would not have caused an outage with traditional settings (e.g., small branches or debris contacting a line). This can lead to a significant increase in the number of unplanned, short-duration outages, which can be frustrating for customers and affect the utility's reliability measures. Consider that each outage also requires a line patrol before the line can be re-energized. Finally, the utility must maintain a constant balance between reliability and safety, considering its risk tolerance and available resources. Finding the right balance requires a deep understanding of local conditions and a willingness to accept more outages for a greater safety benefit.

Examples: Glendale Water & Power uses modified construction standards and grid operations strategies, including the ability to disable reclosers remotely for RFWs. Xcel Energy implements an EPSS program that utilizes a wildfire safety operation that disables reclosing and uses faster trip settings under high-threat conditions. Idaho Power Company uses a limited energy lockout —a 1-shot instantaneous overcurrent protection for high-risk powerlines under high-risk conditions —and a limited energy reclose —a 2-shot instantaneous overcurrent protection on faults — to balance customer impact and wildfire risk when operating reclosing strategies.

Future Direction: The future of protective equipment and settings will be defined by greater intelligence, integration, experience, and more lessons learned. There are many future opportunities in this space, including 1) the use of real-time data from weather stations, cameras, and other sensors to automatically and dynamically adjust protection settings on the basis of current conditions, otherwise referred to as adaptive thresholds, 2) the application of new technologies such as rapid earth fault current limiters and high-impedance fault detections that focus on advanced fault detection and downed conductors, which may not trip traditional relays because of their low current, and 3) the use of AI/ML (which is already on the rise) to analyze vast amounts of multimodal data—including power flow data, line event signatures, weather, fuel moisture, and historical faults—to better predict vulnerable areas and optimize settings to achieve the greatest risk reduction with the lowest impact on reliability.

3.6.3 Adaptive Reclosers

Description of Practice: Adaptive reclosers represent an evolution of conventional recloser technology, introducing the capability to dynamically modify reclosing behavior according to prevailing wildfire risk conditions, weather, and system monitoring (e.g., SCADA) data. Unlike standard devices that follow preset reclosing sequences irrespective of external threats, adaptive reclosers incorporate risk-aware decision-making. For instance, under elevated wildfire risk scenarios characterized by high winds, low humidity, or dry vegetation, they may disable reclosing entirely to prevent reignition following a fault. Conversely, under normal or low-risk conditions, they maintain traditional reclosing cycles to preserve service continuity. This dual capability allows utilities to balance fire mitigation with reliability, adapting operational modes to real-time environmental and system contexts. In a pre-event context, implementing adaptive reclosers requires significant system planning, design, and integration with other sensor systems (including their planning and design), and prioritization of deployment in defined high-risk areas. Note that while fast-trip systems immediately disconnect a line upon fault detection to minimize ignition risk, adaptive reclosing intelligently decides whether and when to re-energize the line based on real-time fault and environmental conditions.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Pre-event planning, design, and deployment of adaptive reclosers reduces the likelihood of ignition events by ensuring that, ultimately, repeated fault energization and potential arcing do not occur during forecasted high-wildfire-probability windows. Specifically, by disabling auto-reclosing in high-risk corridors under high-risk conditions, utilities minimize the risk of conductor arcing, molten material release, or the detection of high-impedance, low-current faults, all of which have the potential to ignite nearby vegetation. At the same time, reclosing remains enabled in safe regions, preserving reliability where risk is low. This condition-aware operation balances fire prevention with service continuity, supporting both safety and resilience in wildfire-prone areas.

Challenges of Implementation: While highly beneficial, implementing adaptive recloser systems in a pre-event context requires a significant capital investment to research, pilot, design, acquire, install, and test intelligent reclosers with communication capabilities. The design phase must carefully consider adaptive settings and their coordination with other protective devices on the circuit (e.g., fuses, relays, and other sectionalizers) to ensure that only the faulted section is isolated; otherwise, a lack of coordination could lead to a larger-than-necessary outage. Adaptive reclosing systems rely on robust and reliable communication networks to send and receive real-time data. In remote, wildfire-prone areas, communication can be a major challenge because of inadequate cellular service or other communication infrastructure, and further investment in communication relays or the adoption of satellite-based communications may be required. For system functionality, adaptive reclosers require highly accurate fire-risk forecasting that incorporates weather, vegetation states, and grid status data. Inaccurate forecasts could lead to overly or underly conservative settings, which would respectively cause unnecessary outages or leave ignition risks unaddressed.

Examples: Avista's dry-land mode allows operators to extend communications to circuit reclosers and remotely adapt protection schemes to align with current fire threat conditions (e.g., implementing hot line holds or single-shot tripping/no automatic reclose). PG&E implements its EPSS program, which involves adjusting reclosers and relays to disable reclosing and enable faster and coordinated trip settings. PG&E is also piloting capabilities like downed conductor detection and investigating rapid earth fault current limiters. SCE uses remote-controlled automatic reclosers to enable recloser relay blocking and fast curve setting in response to weather events. Like PG&E, SCE is moving toward deploying rapid earth-fault current limiters.

Future Direction: Future pre-event advancements in adaptive reclosers can emphasize automation and integration with predictive analytics. AI-driven systems are well-suited to analyzing real-time fire-weather forecasts, vegetation state of stress, and asset condition to autonomously adjust reclosing settings in advance of risk periods. Another direction is linking adaptive reclosers with distributed energy resources, enabling local supply to continue when reclosing is disabled on main feeders. These developments would transform adaptive reclosers from reactive tools into predictive, pre-event instruments central to wildfire preparedness strategies.

3.6.4 Advanced Fire-Safe Devices for Monitoring and Controls

Description of Practice: Advanced fire-safe devices encompass a class of intelligent monitoring and control technologies specifically designed to operate safely in wildfire-prone regions. These include line-mounted fault indicators, conductor-mounted sensors, and automated switches that detect abnormal conditions such as overheating, arcing, or conductor sag. Unlike traditional expulsion-type fuses or surge arresters, which may themselves generate hot particles or sparks during fault interruption, fire-safe devices are engineered to minimize ignition risks while maintaining protective functionality. Their deployment enables utilities to replace high-risk legacy equipment with modern alternatives that integrate seamlessly with advanced protection schemes and supervisory control systems, thereby enhancing wildfire resilience.

System Application: Can be applied to transmission systems, but is traditionally applied to distribution lines.

Risk Mitigation Benefits: The central benefit of advanced fire-safe monitoring and control devices is that they enable rapid, precise detection of fault conditions, allowing utilities to de-energize lines before faults escalate into ignition. By replacing traditional devices that rely on mechanical expulsion or delayed tripping, these technologies significantly reduce the release of sparks, molten particles, or arcs during fault clearing. Intelligent sensors further enhance situational awareness by enabling real-time monitoring of conductor temperature, mechanical strain, and vibrations. These factors are closely linked to wildfire ignition potential. When paired with automated switching, utilities can proactively sectionalize and isolate high-risk segments more effectively, ensuring that the broader system remains operational.

Challenges of Implementation: High installation costs, particularly in remote or rugged terrain, present a barrier for many utilities with large service territories. Integration with existing protection and communications infrastructure requires careful planning, as legacy systems may not support the volume or type of data produced by modern sensors. Furthermore, continuous monitoring generates vast amounts of data, which, without effective analytics and filtering, can overwhelm operators and dilute actionable insights. Ensuring cybersecurity and communications reliability in remote, fire-prone areas also poses technical difficulties. Another challenge associated with using these devices in the pre-event phase is the need for accurate wildfire risk forecasting models. Forecast errors can lead to overly conservative operations (early sectionalization in potentially low-risk conditions) or less effective operations (missed detection during high-risk conditions).

Examples: Surprise Valley Electrification Corporation and Benton REA are specifically using or replacing conventional expulsion fuses with non-expulsion current-limiting fuses. PG&E and Liberty Utilities use remotely controlled technologies that can trip all phases of a line upon detecting a fault in only one phase. Many utilities including PacificCorp, PG&E, Glendale Water and Power, and SDG&E, are using distribution fault anticipation (DFA) / early fault detection (EFD) technology which uses intelligent electronic devices, often radio frequency (RF) monitors or sensors, to analyze electrical system measurements and recognize current and voltage signatures indicative of potential incipient failures before a major fault or ignition occurs.

Future Direction: The future of fire-safe devices lies in integrating edge AI and distributed analytics for predictive fault prevention. By fusing real-time weather data, vegetation growth patterns, and asset condition information, these devices can autonomously assess ignition risks and trigger preemptive responses. These can include actions such as localized de-energization or dynamic protection setting adjustments. Autonomous control would reduce the dependence on operator intervention, thereby shortening response times during critical fire windows. Over time, these systems could also be integrated with distributed energy resources and microgrids, ensuring local supply continuity even when circuits are isolated.

3.6.5 Topology Optimization

Description of Practice: Topology improvements are utilities' efforts to change the structure of the power grid through investments, generally as an initiative to mitigate or reduce PSPS events. The practice involves strategically modifying the physical layout and operational characteristics of the electric infrastructure to alter the network or topological properties of the system.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: By performing topological improvements, utilities create opportunities to sectionalize the grid. For example, looped systems have certain reliability benefits over radial topologies. Implementing these improvements in specific, targeted zones that are within predefined PSPS zones can reduce the likelihood of PSPS events and promote flexibility.

Challenges of Implementation: PacifiCorp specifically noted that mitigating or reducing PSPS events solely through grid topology improvements may be infeasible. Therefore, this best practice is largely considered to be a complementary effort applied alongside other best practices, such as augmenting existing asset circuitry, rather than a complete asset relocation. Reconfiguring or relocating electric infrastructure to mimic topologically optimal systems can be cost-prohibitive, requiring a balance among competing objectives for risk reduction.

Examples: Several WMPs (including those of Liberty Utilities, PacifiCorp, Bear Valley Electric Services, PG&E, and SCE) explicitly state grid topology as a goal for risk reduction, with most noting its potential impact on reducing PSPS events. Additionally, PacifiCorp utilizes circuit topology as a fundamental data element to account for the spatial locations of its facilities and equipment.

Future Direction: Circuit topology can be optimized to mitigate wildfire risk by strategically restructuring assets. Prior to investing resources in optimization, advanced algorithms and scenario testing can be employed to analyze the grid and identify low-risk, high-efficiency reconfigurations that enable operational flexibility. Continual review of strategies, risks, and new technologies will inform best practices related to topology optimization.

3.7 Enhanced Powerline Safety Settings (EPSS) and Public Safety Power Shutoff (PSPS) Integration

Description of Practice: EPSS are preventive measures that utilities can implement ahead of wildfire season to reduce ignition risk. These measures involve configuring protective equipment (relays and reclosers) to have higher sensitivity settings and, in some cases, placing reclosers in non-reclose mode. Because power lines remain in service during periods of elevated risk under EPSS, it is considered an earlier or entirely separate line of defense than PSPS, which preemptively de-energizes relevant lines under extreme fire conditions, generally with the goal of minimizing the outage area as much as possible. Utilities establish predefined environmental thresholds (e.g., high winds, low humidity, dry vegetation) that guide when these measures may later be triggered.

According to the review, approximately 90 utilities (60 percent) with publicly available WMPs have a PSPS protocol in their plans. EPSS measures can include adjusting line sensitivity and switching reclosers/circuit breakers to non-reclose mode, whereas PSPS de-energizes distribution or transmission lines in areas with extreme wildfire risk.

When considering risk evaluations and PSPS protocols, special consideration should be given to de-energized lines near parallel energized circuits, which have been shown to ignite fires due to static charge buildup. For lines included on a PSPS list, verification and possible action are needed to properly ground them and discharge any potential static charge buildup.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: EPSS and PSPS target high-risk lines to minimize the scope and impact of outages and damage. Integration of these practices ensures rapid response during an event, including immediate de-energization of line segments. Additionally, insights from EPSS and PSPS data can improve resilience by identifying opportunities to invest in grid-hardening measures in high-risk areas.

Challenges of Implementation: Implementing EPSS and PSPS results in more frequent, potentially longer power outages, making the balance between risk reduction and reliability a crucial consideration. Having robust data available is important for establishing suitable settings and thresholds for activating EPSS or PSPS that achieve this balance; however, local weather and fuel moisture data can be sparse in remote regions. Additionally, thresholds for activation are determined by the interplay of local conditions, making it difficult to refine them. An additional challenge is coordinating EPSS and PSPS activations to ensure that de-energization and re-energization related to one safeguard do not interrupt the other or mask fault locations. As a further consideration, not all utilities own all of their assets; therefore, an implementation challenge is coordinating, planning, establishing contingencies, and communicating near-term EPSS and PSPS states from generators or bulk-energy providers to downstream utilities.

Examples: Utilities that have integrated PSPS into their operations initiate the process based on a combination of weather, environmental, and operational criteria. Specifically, PSPS is initiated in cases involving poor asset health, line/load criticality, RFWs (Turlock Irrigation District), sustained wind speed and gusts above predefined thresholds (wind gusts ≥ 60 mph for Bonneville Power Administration), low relative humidity (<20–25 percent for Pasadena Water and Power), presence of dry fuels (Wasco Electric Cooperative), and high values on fire-weather indices like energy release component or fire-weather index (Liberty Utilities). Some utilities do not currently implement PSPS or EPSS but plan to do so in the future, including Lewis County PUD No. 1, Jefferson County PUD No. 1 (PSPS only), Clark Public Utilities (PSPS only), Hawaiian Electric Company (PSPS only), and Colorado Springs Utilities (EPSS only).

Future Direction: Utilities should evaluate fuel conditions, line health, and overall fire risk at each season to account for the volatility of environmental factors such as weather patterns and vegetation growth. Some utilities have implemented only EPSS, only PSPS, or neither, if the fire risk is not presently high (e.g., Imperial Irrigation District and Salem Electric), but the risk may change in the near future. EPSS and PSPS are a low-cost alternative to other grid resilience measures, such as system hardening or undergrounding, which require significant infrastructure investment. Lane Electric Cooperative analyzed these measures and determined that, for its grid, the cost of EPSS measures, such as manual line sensitivity and recloser adjustments, was lower than the cost of undergrounding. Similarly, Xcel Energy Public Service Company of Colorado determined that implementing EPSS risk-reduction measures reduces costs when compared to other approaches. For those already implementing EPSS or PSPS, triggers and protocols should be frequently reevaluated. Utilities can bolster wildfire risk preparedness through studies, pilots, and workshops on new risk-mitigation technologies to refine best practices.

3.8 Vegetation Risk and Management

Proactive vegetation management is an integral part of best practices for reducing wildfire risk and maintaining the general reliability of grid services. Encroachment of vegetation in a utility's ROW increases the risk of wildfire starts and power outages due to arcing, sparks, or direct contact between equipment and vegetation. It also reduces the amount of defensible space — the area that helps prevent wildfires from spreading to infrastructure and enables effective firefighting efforts. While the focus of vegetation management is primarily on maintaining ROW, cooperative vegetation management among utilities, adjacent landowners/managers such as state and federal agencies, and other stakeholder groups is gaining attention as a best practice.

Key challenges for utilities pertaining to vegetation management include scope, complexity, and cost. The scope of vegetation management is generally proportional to the size of the ROW managed by a utility, but it tends to be disproportionate to the size of an entire service territory, indicating that more landscape evaluation is needed beyond a utility's control. In addition, each utility's service territory has distinct geography, terrain, and vegetation characteristics, requiring tailored approaches to accommodate the unique scope and complexity of its needs. Vegetation management is often cited as one of the costliest expenditures for maintaining a reliable grid, due in part to scope and complexity, as well as limited resources for implementing extensive wildfire mitigation initiatives.

The most cited sources of best practices for vegetation management include industry standards established by NERC and the American National Standards Institute (ANSI), the integrated vegetation management (IVM) approach established by the International Society of Arboriculture, accreditation programs such as that offered by the Right-of-Way Stewardship Council (ROWSC), and cooperative agreements between utilities and other land managers/owners. While there is considerable overlap among these sources of best practices, IVM and ROWSC are generally regarded as more comprehensive. This section summarizes best practices from each of these sources, including their respective challenges, benefits, key examples, and future directions.

3.8.1 Industry Standards

Description of Practice: Industry standards, such as NERC's FAC-003-5 (NERC, 2022b) and ANSI A300 Tree Care Standards (Tree Care Industry Association, 2023), are widely followed by utilities. The purpose of FAC-003-5 is to maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation on the transmission ROW and to minimize encroachments from vegetation adjacent to the ROW, thereby helping prevent vegetation-related outages that could lead to cascading failures. ANSI A300 standards outline best practices for tree care and vegetation management within the arboricultural community, including aspects specifically relevant to vegetation management by utilities. Notably, FAC-003-5 and ANSI A300 do not specifically address vegetation management to reduce wildfire risk, but they are relevant nonetheless, given their common objective of reducing encroachment. Some utilities have suggested increasing the standard corridor width in established high-fire-risk districts.

FAC-003-5 provides a defense-in-depth strategy that consists of the following requirements, though this reliability standard is focused on transmission voltages of ≥200 kV, or <200 kV for lines that are likely to cause cascading or adverse impacts on the reliability of the bulk electric system if lost:

- Management of vegetation to prevent encroachment inside the flashover clearance or minimum vegetation clearance distance.
- Documentation of maintenance strategies, procedures, processes, and specifications.
- Timely notification to the appropriate control center of vegetation conditions.
- Corrective actions to ensure that flashover distances will not be violated as a result of work constraints such as legal injunctions.
- Annual inspections of vegetation.
- Completion of annual work to prevent flashover.

ANSI A300 standards are technical guidelines developed by the Tree Care Industry Association to provide best practices for tree care and vegetation management. The standards are divided into eight parts: tree pruning, tree risk assessment, tree support systems, tree planting and transplanting, IVM, soil management, tree lightning protection, and tree inventory and management plans. The parts that are most applicable to utilities and reducing wildfire risk are those on IVM (Section 3.8.2) and tree inventory and management plans. ANSI A300 standards are applicable to vegetation management for both transmission and distribution infrastructure.

A comparison of FAC-003 standards with IVM principles and best practices reveals that most elements of IVM are not addressed by FAC-003 (Goodrich-Mahoney, 2008). The FAC-003 standards focus almost exclusively on documentation and activity associated with only four IVM elements: 1) tolerance levels reflecting when vegetation needs to be treated, 2) inventorying vegetation to determine whether there is a need for treatment with reference to tolerance levels, 3) strategically planning for treatment, and 4) monitoring reliability. The FAC-003 standard includes almost none of the performance elements that are social or environmental (e.g., community relations and workers' rights, account for economic and ecological effects of treatments). However, many of these missing elements in the NERC standards are covered by the voluntary ANSI A300 standards. Thus, if the mandatory NERC FAC-003 standards and the voluntary ANSI A300 standards are combined to guide practice, transmission organizations will effectively practice IVM.

Note that while FAC-003-05 is technically a standard, it is mandatory for transmission lines with a voltage of ≥200 kV and small voltage lines that are likely to affect the bulk-power system, and utilities may be subject to fines by NERC if they do not adhere to this standard. As such, some states have additional regulations pertaining to vegetation management that utilities must follow. For example, Oregon and California set minimum vegetation clearance distances for electric infrastructure (Oregon Public Utility Commission, 2025; California Public Resources Code §4292 and §4293). Additionally, many states require utilities to develop vegetation management programs, including but not limited to, California (California Public Utilities Commission General

Order 95, Rule 35), Texas (Public Utility Commission of Texas Title 16, Part 2, Rule 25.96), New York (New York Codes, Rules and Regulations Title 16, Part 84; New York State Public Service Commission, 2025), and Colorado (Colorado Senate Bill 19-107).

The NERC FAC-003-5 standard applies to transmission and generation facilities that are operated at 200 kV or higher; are operated below 200 kV but if lost are identified as likely to cause cascading or adverse impacts on the reliability of the bulk electric system; or are designated as part of the bulk electric system. The NERC FAC-003-5 standard does not apply to distribution infrastructure. ANSI A300 standards apply broadly to vegetation management, including in utility ROWs, and thus are applicable to both transmission and distribution infrastructure.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: While the NERC FAC-003-5 standard focuses on preventing major interconnection system failures and outages caused by vegetation contact and flashovers, it can indirectly reduce wildfire risk by requiring utilities to minimize the risk of vegetation coming into energetic contact with transmission lines. Furthermore, it requires annual inspections and measures to prevent flashover. ANSI A300 standards extend beyond the basic goal of FAC-003-5 to manage encroachment by promoting IVM practices that are more comprehensive and beneficial for long-term reliability and wildfire risk reduction. In addition, the standards emphasize other benefits, such as improved worker and public safety, tree health and longevity, and environmental responsibility.

Challenges of Implementation: NERC's FAC-003-5 requires annual vegetation inspections of transmission infrastructure, which can be extensive and costly for some utilities. These challenges are compounded by limited access to infrastructure in remote or rugged terrain, limited workforce availability, and environmental and legal constraints. Another challenge is timing. Vegetation inspections ideally should occur during the onset of the growing season (and before peak wildfire season) to identify potentially hazardous vegetation before it grows into the minimum vegetation clearance distance zone. This ideal inspection window can be quite short, especially in areas more prone to wildfire or experiencing prolonged drought.

ANSI A300 standards are voluntary; thus, it may be difficult to encourage utilities to adopt standards beyond those required by FAC-003-5 or to achieve wider adoption of practices more consistent with IVM. ANSI A300 standards emphasize practices that preserve tree health and prevent habitat destruction. However, these practices sometimes conflict with the aggressive trimming that the utility needs to do to reduce risks, and they can be a politically sensitive topic among stakeholders. These standards are also highly technical and require more detailed training. Following ANSI A300 standards also requires recurring treatment to achieve long-term effectiveness, meaning utilities must invest in ongoing maintenance programs.

Other challenges that apply to both standards include difficulty coordinating with stakeholders, limited budgets, and interannual variability of wildfire seasons, droughts, and extreme weather that can exacerbate challenges in meeting clearance requirements. Given the range of challenges they face in vegetation management, utilities are often forced to prioritize high-risk areas, which may leave lower-risk areas undermaintained.

Examples: FAC-003 standards are mandatory for utilities operating transmission systems within the jurisdiction of NERC, such as PG&E (California), SCE (California), Duke Energy (the Southeastern United States), Xcel Energy (Colorado, Texas, and the Midwest), NextEra Energy

(Florida), Dominion Energy (Virginia and North Carolina), Tennessee Valley Authority (the Southeastern United States), Bonneville Power Administration (the Northwest), FirstEnergy Corp. (Pennsylvania, Ohio, and Mid-Atlantic), and NV Energy (Nevada). All these utilities also follow certain aspects of ANSI A300 standards, particularly those pertaining to IVM. Additional examples of utilities that follow ANSI A300 include National Grid (the Northeastern United States), Ameren (Missouri and Illinois), and SDG&E (California).

Future Direction: Utilities are increasingly investing in advanced tools and remote sensing technologies, such as lidar, drones, GIS, and predictive analytics, to enhance the detection of hazardous vegetation and improve the overall efficiency of vegetation management programs. Collaborative partnerships among utilities, private landowners, local governments, and environmental stewardship programs are also seen as a beneficial approach to improving compliance with industry standards.

3.8.2 Integrated Vegetation Management

Description of Practice: IVM is a systematic approach to managing plant communities around and under electrical assets (International Society of Arboriculture, 2021). The core principle of IVM is to identify both compatible and incompatible vegetation species, then select and implement the most appropriate, environmentally sound, and cost-effective control methods to achieve specific management objectives. IVM focuses on managing tree and vegetation species in and immediately adjacent to the ROW to prevent future clearance issues and promote fire-resilient, sustainable vegetation communities that are low-growing and compatible with electrical facilities.

IVM generally consists of site assessment, control, evaluation, and maintenance. Site assessment involves describing the geography, vegetation communities, and wildlife habitat needs of a given area to help contextualize appropriate management actions. Control of vegetation is achieved through multiple methods, including mechanical methods (e.g., mowing, pruning, and cutting), chemical methods (selective use of herbicides), biological methods (e.g., grazing and the addition of specialist insect herbivores), and cultural control (promoting fire-resistant, low-growing vegetation). The choice of method is dependent on multiple factors, including effectiveness, safety, cost, and environmental impact. Regular evaluation is key to determining a program’s efficacy and making necessary adjustments. Finally, IVM is a long-term approach that stresses the maintenance of vegetation management to reduce costs and risks over time.

Another key aspect of IVM is prioritizing vegetation management using a risk framework. The framework may be customized according to a utility’s or landowner’s needs and unique risk factors within its service territory. Common risk factors include being in a high-fire-risk area, criticality of infrastructure and impacts on the bulk electric system, and being in a storm-prone area.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: The primary objective of IVM is to minimize the risk of vegetation-related outages and wildfire ignitions. In addition, the use of a multi-method control approach reduces the need for redundant or reactive vegetation control measures, thereby minimizing the cost of vegetation management over time. IVM also promotes ecological health by prioritizing native plant species to create low-growing, fire-resistant communities.

Challenge of Implementation: IVM is widely recognized as a best practice, but it can involve significant costs for utilities; thus, it will be a challenge for utilities to fund these efforts without increasing costs to consumers. Achieving a “mature” maintenance state for ROWs through IVM requires commitment and substantial time and resources. Utilities must balance mitigation costs with the resulting reduction of wildfire risk. Furthermore, IVM is a voluntary practice and thus requires additional incentives for utilities to adopt it, given its potentially significant cost. To this end, continued publicization of IVM “success stories,” new financial incentives (e.g., federal or state grants or cost-sharing), and creative partnerships may help increase the adoption of IVM practices. Additional challenges include environmental and legal constraints related to certain IVM techniques, such as herbicide use or aggressive pruning, which can be hazardous to human health or wildlife habitats. Utilities may also experience significant obstacles obtaining permits to perform vegetation management for ROWs on public lands as these areas are subject to compliance with Section 7 of the Endangered Species Act and Section 106 of the National Historic Preservation Act. From an agency perspective, federal land management entities, such as BLM, face challenges in overseeing and ensuring consistent compliance (e.g., PIM2025-007; BLM, 2025) for IVM across diverse utilities with extensive corridors.

Examples: The use of IVM to help reduce wildfire risk in ROWs is cited in the WMPs of numerous utilities, from small to large. Some examples include Arizona Public Service (Arizona), Avista (the Northwestern United States), Black Hills Energy (Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota, and Wyoming), City of Shasta Lake Electric Department (California), Clark Public Utilities (Washington), Hermiston Energy Services (Oregon), Klickitat PUD (Washington), Liberty Utilities, NorthWestern Energy, PacifiCorp, PG&E (California), Sacramento Municipal Utility District (California), San Francisco Public Utilities Commission (California), Seattle City Light (Washington), SCE (California) Umatilla Electric Cooperative (Oregon), United Power, and Xcel Energy (Wisconsin, Michigan, Colorado, and New Mexico).

Future Direction: Key areas where IVM is advancing include the adoption of advanced technologies, increased use of fire-resistant vegetation, expanded integration of sustainable practices, and cross-sector collaboration. Examples of advanced technologies include AI/ML, remote sensing (e.g., LiDAR, drones, and satellite imagery), and smart sensors. The use of fire-resistant vegetation emphasizes planting native plant species with lower fuel loads or experimenting with regenerative practices, such as permaculture or controlled burns. Sustainable IVM practices that are gaining more attention include promoting pollinator habitats, erosion control, reduced or targeted herbicide use, increased use of grazing animals to manage vegetation, and repurposing of ROWs for green initiatives such as renewable energy projects. Finally, more utilities are employing cross-sector collaboration by partnering with conservation organizations to align IVM programs with broader ecological goals and working with firefighting agencies to establish defensible space.

3.8.3 Accreditation Programs

Description of Practice: Several accreditation programs exist for electric utilities to ensure vegetation management aligns with industry best practices, regulatory standards, environmental stewardship, and safety goals. These programs can provide recognition and credibility, validate adherence to IVM approaches, and enhance accountability for utility. ROWSC offers a widely recognized accreditation program for utilities that demonstrate sustainable vegetation management practices. ROWSC’s accreditation is based on adherence to 10 environmental and social sustainability principles (ROWSC, 2025b):

- *Laws, standards, and best management practices:* Demonstrate awareness of laws and regulations pertaining to vegetation maintenance for electric infrastructure.
- *Tenure, use rights, and responsibilities:* Clearly define and document the long-term right of use of the land.
- *Stakeholder relations:* Provide IVM outreach to affected stakeholders.
- *Management planning:* Document standards, objectives, principles, procedures, and practices pertaining to IVM.
- *Understanding pest and ecosystem dynamics:* Ensure personnel are knowledgeable about incompatible and compatible plant communities and understand the effects of various IVM methods.
- *Tolerance levels and action thresholds:* Schedule vegetation management actions on the basis of local conditions or implement them when tolerances are exceeded or expected to be exceeded.
- *Vegetation control methods and treatments:* Use a variety of control methods, rather than just one or two, in a targeted and prescriptive manner.
- *Economic and ecological effects of control methods:* Take into consideration cost-effectiveness and ecological effects when selecting vegetation management treatments.
- *Site-specific implementation of treatments:* Divide ROW corridors into vegetation maintenance units based on their operational, economic, ecological, and ownership significance.
- *Monitoring and adaptive management:* Evaluate the success of decision-making and the effectiveness of management actions.

Another accreditation program is Tree Line USA, offered by the Arbor Day Foundation in collaboration with the National Association of State Foresters (Arbor Day Foundation, 2025). The program consists of five standards:

- Quality tree care: Adopt work practices that are consistent with ANSI A300 and IVM, avoid damaging trees when installing underground utilities, implement a quality assurance program for vegetation management, and assess impacts to urban forests and community trees.
- Annual worker training: Ensure that employees and contractors who perform vegetation maintenance for utilities complete annual formal training.
- Community tree planting and public education: Allocate an annual expenditure of at least 10 cents per customer for use in community tree planting programs throughout the service area, and contact all homeowners and customers once a year to provide educational information on tree-related utility issues.
- Tree-based energy conservation program: Promote the benefits of trees in energy conservation.
- Arbor Day observance: Participate or sponsor annual Arbor Day events.

Additional accreditation programs include the Audubon Cooperative Sanctuary Program (Audubon International, 2025) and Wildlife Habitat Council (WHC) Conservation Certification. Utilities less frequently participate in these programs than in the ROWSC and Tree Line USA programs because the programs are less focused on reducing wildfire risk or improving grid reliability. The Audubon Cooperative Sanctuary Program is designed to assist with site assessment and environmental planning, wildlife and habitat management, water management, resource management, and outreach and education. The WHC Conservation Certification encourages leadership in biodiversity and ecologically conscious vegetation management (e.g., pollinator habitat creation, invasive species management, and native plant promotion along ROWs).

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Among the accreditation programs described here, ROWSC's program has the most direct application to reducing wildfire risk in ROWs by ensuring qualified utilities practice IVM, prioritize vegetation management in high-fire-risk areas, and strive to use fire-resistant native species. Additional benefits of ROWSC's program include better power system reliability, assured regulatory compliance, enhanced community relations, reduced costs over time through proactive management, and recognition through continuous improvement (ROWSC, 2025a). The other accreditation programs (i.e., Tree Line USA, the Audubon Cooperative Sanctuary Program, and the WHC Conservation Certification) primarily benefit environmental sustainability, stakeholder collaboration, and worker safety, which are important aspects of vegetation management by utilities. Another benefit of accreditation programs is that participants become part of a network of other accredited organizations, improving the sharing of institutional knowledge and best practices related to vegetation management.

Challenges of Implementation: All accreditation programs are voluntary and likely incur additional costs for utilities; therefore, it may be difficult to persuade utilities to participate in these programs without offering additional incentives. However, it should be noted that the use of IVM required by ROWSC's accreditation program is intended to reduce costs over time through proactive management practices. ROWSC's accreditation is awarded for five years. However, during this period, the utility must undergo several desk audits and an on-site audit to maintain accreditation (ROWSC, 2025a).

Examples: Examples of ROWSC-accredited utilities in the United States include Liberty Utilities (Missouri, Kansas, Oklahoma, and Arkansas), Bonneville Power Administration (the Northwestern United States), New York Power Authority (New York), Arizona Public Service (Arizona), Vermont Electric Power Company (Vermont), Sacramento Municipal Utility District (California), and FirstEnergy Corp. (Ohio, Pennsylvania, New Jersey, West Virginia, Maryland, and Virginia). ROWSC has also accredited two utilities in Canada (ATCO and AltaLink).

Future Direction: To our knowledge, the ROWSC has not explicitly outlined future directions for its program; however, given its focus on IVM, the ROWSC may incorporate emerging best practices among the IVM community into its accreditation requirements in the future. In summary, these include the use of remote sensing technology (e.g., lidar, drones, or satellite imagery) to monitor vegetation growth, increased use of fire-resistant vegetation, expanded integration of sustainable practices, and cross-sector collaboration (see Section 3.8.2 for more details).

3.8.4 Cooperative Agreements

Description of Practice: Many utilities have cooperative agreements—whether formal (e.g., a memorandum of understanding) or informal—with other land managers, such as government agencies, conservation organizations, and private landowners, to collaborate on vegetation management. The purpose of these agreements is to coordinate efforts to reduce costs and wildfire risk, while balancing operational needs with environmental stewardship. Activities carried out under these agreements can include joint vegetation-clearing projects to create defensible space or remove hazardous vegetation, the sharing of resources for monitoring and maintaining vegetation near ROWs, the implementation of cross-training programs between utility and partner organization crews, joint vegetation restoration and native species planting programs, joint forest thinning efforts to reduce fuel loads, and conservation-focused agreements to improve biodiversity or wildlife habitat.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Cooperative vegetation management agreements are mutually beneficial to utilities and adjacent landowners, reducing wildfire risk by helping prevent infrastructure-related ignitions and the uncontrolled spread of wildfire from or into adjacent lands. ROWs can serve as strategic wildfire breaks and provide firefighting personnel access to otherwise inaccessible areas. Other mutual benefits include improving efficiency, sharing resources, and reducing risk to infrastructure, natural resources, and urban development. Cooperative agreements also enable utilities to better align their vegetation management practices with the various land uses and conservation goals of surrounding regions.

Challenges of Implementation: Challenges associated with cooperative agreements typically arise from differences in goals, operational priorities, regulatory requirements, and resource availability, as well as the need for collective buy-in among participating entities. For example, vegetation management decisions made by state and federal land managers are driven in part by conservation goals, which may conflict with utility priorities for clearing vegetation in ROWs. Regulatory requirements may include an environmental impact assessment that includes resource and wildlife surveys, cultural surveys, assessments of community impacts, mitigation measures, an exploration of alternative approaches, and public comment. Disagreements over ROW access rights and legal restrictions on vegetation control measures (e.g., mechanical, chemical, or biological) on protected lands are common legal and regulatory challenges. Differences in resource availability may arise, such as utilities lacking funding for conservation initiatives that state and federal agencies prioritize in their agreements or landowners lacking the resources to support utilities in implementing large-scale vegetation-clearing projects. Difficulty getting collective buy-in or approval from participating entities can lead to significant delays in implementing vegetation treatments. Maintaining trust among cooperating entities can also be a challenge, given differences in their priorities and operational goals. Complex jurisdictional issues and cultural sensitivities are a common challenge because ROWs often traverse lands managed by multiple stakeholders.

Examples: Many utilities have formal partnerships with state and federal land management agencies. One of the more expansive agreements is a memorandum of understanding among Edison Electric Institute, the Utility Arborist Association, and multiple federal agencies, including the U.S. National Park Service, the U.S. Fish and Wildlife Service, BLM, USFS, and the U.S. Environmental Protection Agency (2016). The Edison Electric Institute represents all U.S. investor-owned utilities that operate in all 50 states and Washington, DC. Additional examples include PG&E (California), which has partnerships with CAL FIRE, BLM, and USFS to enhance vegetation management in areas prone to wildfires. Arizona Public Service (Arizona) has a memorandum of understanding with BLM and the Arizona Department of Forestry and Fire Management to reduce hazardous vegetation along shared ROWs and provide cross-training programs. SCE has cooperative agreements with CAL FIRE, the U.S. National Park Service, and local and regional conservation groups to maintain defensible space and conduct joint fire prevention and vegetation restoration activities. The Bonneville Power Administration (the

Northwestern United States) is one of four federal power marketing administrations and has cooperative agreements with USFS, BLM, the Washington Department of Natural Resources, and other government agencies to conduct joint ROW assessments, conduct forest thinning and hazardous tree removal, and implement conservation initiatives. Some utilities, such as PG&E, Salt River Project, Liberty Utilities, and Idaho Power, have also formed partnerships with forest agencies to sponsor forest thinning projects outside ROWs to improve forest habitat and mitigate wildfire risks that may encroach upon easements or otherwise threaten lines. This provides benefits not only to utilities but also to the communities they serve.

Future Direction: Continued coordination between utilities and ROW-adjacent entities, such as BLM or USFS, ensures a holistic approach to wildfire risk mitigation that benefits all landowners. Increasing trends in wildfire size and severity, as well as extreme weather events, are likely to drive cooperative vegetation management agreements to place greater emphasis on creating a fire-resistant landscape and developing predictive modeling tools to evaluate vegetation and wildfire risk. The use of advanced remote sensing technologies to monitor vegetation in ROWs and adjacent lands is also likely to become increasingly important in cooperative agreements, as some agencies may have better access to or expertise with these technologies. Joint conservation initiatives, such as planting pollinator-friendly species in ROWs and creating wildlife corridors, have been successful in many areas and are increasingly common in cooperative vegetation management agreements. Pending bi-partisan legislation, the Fix Our Forest Act (S. 1462), last updated October 30, 2025, draws from recommendations of the 2023 Wildland Fire Mitigation and Management Commission and aims to address the multi-faceted issues in forest management and proposes a comprehensive framework to scale up forest restoration efforts (Wildland Fire Mitigation and Management Commission, 2023; U.S. Senate, 2025). This includes expedited administrative procedures for planning and permitting, consistent processes for utility rights-of-way (Title II, Sec. 211), mandating the enhanced integration of scientific and technological advancements into practice, authorizing community-focused wildfire risk mitigation programs, revising existing statutory forestry authorities, and providing for improved efficacy in post-fire rehabilitation and emergency wildfire response.

3.9 Wildfire Hazard Modeling

3.9.1 Wildfire Spread Models

Description of Practice: Wildfire spread models simulate the spread of a fire from a defined ignition point or a near-real-time fire perimeter. These models simulate the rate and location of a fire's spread over time, often including random (stochastic) perturbations to the prescribed weather variables (such as wind speed and wind direction). Situational awareness of the fire is enhanced through these simulated "match drop" calculations, producing "what if" scenarios that form the building blocks of landscape wildfire simulation systems, supplementing the estimation of fire burn probabilities for a time period (Section 3.9.2). Fire spread models comprise numerous sub-models that account for the complex processes that occur during a wildfire, including surface and crown fire behavior, the propagation of the fire front across the landscape, spotting, and suppression activities. The underlying formulation and research are consistent across models commonly used by public and commercial entities, differing primarily in implementation and interfaces for specific users (e.g., land managers or electric utilities).

Wildfire spread models require various data inputs. Topographical data (for slope, aspect, and elevation) is highly detailed and remains largely static. Fuel (vegetation) data changes over time and should ideally be updated at least annually to account for disturbances (e.g., logging, vegetation die-off, fires, or landslides) and land-use changes. Fuel disturbances are tracked by federal agencies, although updates to these datasets lag behind observations by a year or more and are not comprehensive of all landscape disturbances. Meteorology (wind, temperature, and humidity) and its influence on fuel moisture can vary substantially depending on the goal of the modeling, such as using historic meteorology to understand the observed behavior of a fire or using forecast meteorology (often provided as an ensemble of possible weather conditions) for predicting the spread of an active wildfire.

These models produce a time series of outputs. An individual simulation of a wildfire spread model includes hourly output describing the progressive perimeters of the wildfire, the estimated flame length at the leading edge of the fire, and the rate of fire spread (distance/time). The aggregation of this individual simulation among many other additional simulations with slight random perturbations to the meteorology or fuels data yields a suite of perimeters and expansion rates over time that can be overlaid and compared, presenting both "what if" scenarios as well as a visual and quantifiable perspective for how small variations may affect the fire spread. Furthermore, the set of simulations can be used to determine the best-case, worst-case, and most likely scenarios of fire spread and impacts to assets.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: "Match drop" simulations for specific electrical assets can help justify investment decisions like whether to perform infrastructure hardening or the decision of whether to include a line on a PSPS list. These simulations can also be run retroactively to estimate what could have happened had a preventive measure not been taken. Active fire spread forecasting informs utilities whether their assets are at risk—supporting resource allocation and adjustments to field operations and system protection schemes—and whether a PSPS should be implemented.

Challenges of Implementation: Wildfire spread models are complex and require resources and expert understanding. Thus, they are commonly employed by larger utilities that have either the resources to contract wildfire experts or an in-house wildfire team. Advanced modeling implementation also includes more granular, up-to-date data, with annual updates to dynamic inputs such as fuels and meteorology. Additionally, these models provide the probability and intensity of wildfire, but they do not natively provide an exposure assessment for grid assets. Utilities must have additional resources to interpret and act on risks identified in modeling outputs, integrating them into planning and response workflows.

Examples: A variety of open-source and commercial wildfire spread models are available. These models largely use the same empirical models to simulate fire spread, with their primary differences in implementation, user interface, modes, and modules. However, there are models that rely on more sophisticated physics-based computational fluid dynamics models with coupled land-atmosphere interfacing, as well as cellular automata–based models. The commercial products may require less expertise to run but come at a significant cost, whereas the open-source models have no upfront cost but require a background in fire science and the ability to set up and run computer modeling simulations, and to process and evaluate the outputs.

- The following utilities note the use of a commercial wildfire spread model: Anaheim Public Utilities, Arizona Public Service, Bear Valley Electric Service, Idaho Power Company, PacifiCorp, Rocky Mountain Power, San Francisco Public Utilities Commission, SCE, Xcel Energy Northern States Power Company, Xcel Energy Public Service Company of Colorado, and Xcel Energy Southwestern Public Service Company.

- The following utilities note the use of an open-source wildfire spread model; in some cases, utilities are using or evaluating both: PacifiCorp, PG&E, SCE, Bear Valley Electric Service, Idaho Power Company, and Liberty Utilities.

Future Direction: More efficient, larger-scale, and frequently updated modeling methods are needed to enable all types of utilities to utilize wildfire behavior and spread models. Some model inputs are frequently out of date, such as historical meteorological data (which do not account for trends in fuel aridity or extreme wind events), historical ignition data over a relatively short time period, and old fuel data that lack local knowledge inputs or fail to account for the wildland-urban interface, vegetation health, or agricultural fuels. These data inputs can be improved through the use of AI/ML algorithms and a growing suite of observational data, such as satellite remote sensing data. Many simulation systems are costly, computationally expensive, or difficult to use. Investing in more efficient, open-source models and developing more intuitive interfaces could significantly enhance wildfire hazard modeling capabilities for all utilities. Future work is needed to assess the relationship between wildfire conditions and grid asset exposure. The most effective approach is to develop wildfire fragility curves that are responsive to dynamically changing conditions. Because of the complexity and expert knowledge required to run wildfire models, considering regional utility cooperatives or consortia that can run regional wildfire risk models may be beneficial, where experts housed within one utility can benefit others with fewer resources, provided equitable contributions are established.

3.9.2 Landscape Wildfire Simulation Systems

Description of Practice: Landscape wildfire simulation systems utilize many individual wildfire spread model simulations to estimate burn probability and fire behavior across a landscape. As part of the model setup, these systems consider a set of weather and ignition inputs with random perturbations to represent a wide array of scenarios across the landscape and fuelscape (a representation of the latest vegetation fuels information). These simulation systems are not intended to predict the occurrence or development behavior of a particular fire but instead describe a range of outcomes reflecting wildfire burn probability and expected fire intensity. Landscape wildfire simulation systems also provide a key component for developing and defining high-wildfire-risk districts (HFTDs) as they incorporate fuels, terrain, ignition and fire behavior history, and meteorological history to define the probabilistic hazard risk. For an area the size of the State of California, the randomization and perturbation steps of such models can result in millions of individual wildfire simulations, which are then used to summarize wildfire likelihood and intensity.

The emerging area of integrating ML with traditional wildfire simulation models has led to the development of hybrid frameworks that combine the strengths of wildfire spread models and data-driven approaches. ML is often incorporated into the preparation of model inputs but is also used directly for modeling, where methods such as support vector machines and gradient boosting have been employed to predict ignition probabilities based on historical fire data and current environmental conditions (Singh et al., 2024). Some utilities have utilized ML-based models to calculate the probability of ignition for electrical assets based on contact type, such as equipment failure or vegetation contact.

The primary outputs of landscape wildfire simulation systems include burn probability, which is the number of times a spatial unit burns divided by the total number of simulations, and flame length, typically represented by the average modeled flame length over a spatial unit. Outputs from these model simulations are informative on their own and can also be integrated with consequence analysis modeling (Section 3.10) to produce a comprehensive wildfire risk product across the service area.

Wildfire simulation outputs like burn probability and flame length (intensity) can be ingested into risk modeling frameworks and consequence analyses (see Section 3.10). Broadly speaking, ignition probability/intensity mapping (maps from wildfire risk models that show the probability of ignition/fire intensity along electric lines and equipment) allows utilities to quantify wildfire risk across regions, circuits, conductor spans, or individual assets. Utilities use this approach to assess asset exposure, prioritize grid hardening, and implement preemptive, targeted vegetation management.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Utilities can use the outputs of wildfire risk modeling to inform strategic risk-mitigation investment decisions that yield the greatest benefit. The system's application of wildfire risk modeling can lead to reduced grid-initiated ignitions, which translate into reliability, financial, regulatory, and insurance-related advantages (reduced claims and liability exposure drive down insurance premiums for both utilities and ratepayers). Additionally, quantifiable mitigation outcomes—documented via model-driven before-and-after scenarios—bolster grant applications and access to federal resilience funding.

Challenges of Implementation: Similar to wildfire spread modeling, the main challenges in implementing landscape wildfire simulation systems concern complexity, cost, and interpretation. By requiring potentially millions of individual wildfire spread forecasts, simulation systems require even more resources. In addition to facing the same data challenges that affect wildfire spread modeling, results from landscape wildfire simulation systems can be difficult to interpret. Burn probability is a primary output of these systems, and in many cases, the probability represents the likelihood of an area burning in a typical year, without accounting for any current information (e.g., an active drought or weather outlooks), and thus making burn probabilities not directly comparable to the current year of wildfire activity. Because of the random nature of these low-frequency wildfire events, the simulation results need to be compared with wildfire activity data over a long period (e.g., a decade) to assess their accuracy. However, this is not as actionable as using wildfire activity from the past year. As noted in Section 3.9.1, assessing how wildfire conditions affect grid assets requires developing dynamic wildfire fragility curves. Since the complex modeling needed for this work demands significant expertise, a collaborative approach among regional utilities or consortia is advisable. Such a partnership would allow smaller, less-resourced utilities to benefit from the expert knowledge housed within larger organizations, under an agreement for equitable cost-sharing.

Examples: Common landscape wildfire simulation systems are available in both open-source and commercial spaces. These systems utilize their underlying wildfire spread model (Section 3.9.1) but are typically run over thousands of possible scenarios to achieve a probability of burn and intensity. The models will differ in their implementation, user interface, modes, and modules.

- Various commercial landscape wildfire simulation systems are used by the following: Anaheim Public Utilities, Arizona Public Service, Bear Valley Electric Service, Idaho Power Company, PacifiCorp, Puget Sound Energy, PG&E, Rocky Mountain Power, San Francisco Public Utilities Commission, SDG&E, SCE, Xcel Energy Northern States Power Company, Xcel Energy Public Service Company of Colorado, and Xcel Energy Southwestern Public Service Company.

- Various openly available landscape wildfire simulation systems are used by the following: PacifiCorp, PGE, PG&E, SCE, Bear Valley Electric Service, Idaho Power Company, Liberty Utilities, and Mason County PUD No. 1.
- The following utilities have noted the incorporation of ML into their processes: SDG&E Company used an ML gust forecast model trained with random forest and eXtreme Gradient Boosting, and SCE used an ML model to simulate the probability of asset ignition.

Future Direction: The combination of data requirements, modeling expertise needs, and computational costs makes the use of simulation systems difficult, especially for smaller utilities. Thus, many utilities employ contractors who specialize in running these simulation systems or purchase costly, but easier to use, commercial software to run simulations. Efforts need to be made to achieve more effective deployment of simulation systems, develop guidance on the use and interpretation of model outputs, and properly convey the uncertainty inherent in these simulation systems. Cost issues could be addressed by smaller utilities pooling resources regionally, such as cost-sharing for modeling efforts under a single contract or sharing data and analytics.

3.9.3 Detection of Emerging Risk

Description of Practice: The fact that wildfire risk, traditionally an issue in the Western United States, is now affecting larger segments of the country, including areas previously considered low risk, highlights the importance of detecting emerging risks in the wildfire landscape. Furthermore, for utilities with expansive and diverse service territories, areas that were historically deemed low risk are now showing signs of change. Utilities are enhancing their predictive modeling to proactively identify and adapt to emerging wildfire risks in regions that have not traditionally received attention. Some utilities are mandated to identify geographic areas within their service territory that pose a higher wildfire threat than currently reflected in existing fire threat maps (e.g., California Public Utilities Commission fire threat maps) and use updated information about the area or changes in environmental conditions to propose areas that should be added to the defined high-fire-risk districts. Utilities also incorporate medium- and long-term trends in temperature, humidity, fuel/soil moisture, and vegetation distribution into their risk modeling to identify new areas of concern. Other factors, such as changes in land use, can also play a significant role in emerging risks. This active reevaluation process is a direct mechanism for detecting emerging risks in new locales. Many utilities continually monitor for significant changes in ignition risk drivers that could alter the fire threat in a specific area, and if their assessment finds existing fire threat ratings insufficient, they can be required to or opt to identify those areas for potential high-fire-risk district modification. Mitigation actions taken by utilities in their transmission and distribution systems are similar to those described in Sections 3.9.1 and 3.9.2.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: The benefits of detecting emerging risks are largely the same as those described in Sections 3.9.1 and 3.9.2.

Challenges of Implementation: The practice of identifying emerging risks faces particular challenges because it aims to capture/quantify something previously unseen (at least in some respects). As is the case with wildfire modeling and simulation in general, insufficient data quantity or granularity presents hurdles to detecting trends, and transferring the implications of historical trends from risk-familiar regions to new regions necessitates a critical examination of underlying assumptions, which may not be equally valid across disparate spatial and temporal domains. Uncertainty in medium- and long-term model projections also requires careful consideration when the outputs potentially steer the allocation of prevention and mitigation resources.

Examples: Bear Valley Electric Service and SDG&E regularly assess (at least once per year) the high-fire-risk district for potential changes. Redding Electric Utility seeks to identify previously unidentified risks through joint efforts with other publicly owned electric utility associations and reviews of historic fire records. SCE performs root cause analysis on ignitions and near-misses (redefined as “risk events”) to detect patterns or correlations. SCE detected an increase in fires caused by secondary wires in 2021, leading to enhanced inspections and demonstrating the detection of a new or heightened specific risk driver.

Future Direction: The advancement of cutting-edge modeling and ML techniques offers promising opportunities to refine emerging risk identification. Complex relationships among environmental variables, the built environment, and historical fire patterns can be uncovered and used as a touchstone for early risk detection in novel contexts. The trend toward higher-frequency collection of higher-quality observational data, such as satellite and aerial remote sensing, further opens the door to more targeted and higher-fidelity identification of emerging risks. Additionally, establishing more consistent definitions for the data and criteria used to identify high-wildfire-risk districts would be beneficial.

3.10 Consequence Analysis

Description of Practice: Consequence analysis describes how such an ignition event would result in public harm, infrastructure damage, and associated economic losses. The intent of consequence analysis is to designate a utility’s monetary investment for wildfire risk reduction with specific actions at specific locations to reduce wildfire risk to and from infrastructure. Consequence analysis is conducted during the wildfire pre-event stage (see Figure 2). The results are informative for near-future actions during the wildfire event and for post-event recovery. In some cases, consequence analysis may use wildfire modeling to identify locations and weather conditions associated with high fire risk; however, such a single data input (such as 2026 burn probability) would be combined with multiple other private and public data layers.

Examples of private utility data may include pole/tower height, conductor spacing, and conductor span distance, which can be used to estimate when conductors may contact each other during periods of high temperature (causing them to lengthen) and high wind speeds (such as during RFWs). Utilities also have private data regarding asset health, in-place infrastructure hardening, which transmission lines would have the least effect on the public if they were to be de-energized and electricity re-routed, and which single transmission corridors supply the most people (in the millions) with electricity (such as the Pacific DC Intertie connecting northern Oregon to Los Angeles, which had near-overlap with Oregon’s 2021 Bootleg Fire).

Examples of public geospatial data that a utility sometimes considers in its consequence analysis include information on the locations of hospitals, nursing homes, park boundaries, building footprints, communication towers, wastewater treatment centers, drinking water treatment plants, prisons, emergency medical services, emergency operations centers, natural gas plants and pipelines, data centers, and other key facilities. Most of the relevant datasets were publicly available from the U.S. Department of Homeland Security Geospatial

Management Office prior to August 27, 2025, but are now subject to individual data clearance to access.

Various datasets describing a utility's various societal and environmental exposures to wildfire should ideally be aggregated with the same "currency" (Finney, 2005). This means that a location's burn probability (0–100 percent), the number of nursing home beds within 0.5 miles, and the asset health of the conductor line may all be inputs to estimating a location's consequence value. The latest public report by PG&E (Wildfire Consequence Model Version 4) reflects the aggregation of data from several sub-models for different wildfire risk factors, such as fuels likely to start a wildfire, a location's weather, and human risk factors in the area (e.g., building density, road miles per person, and proximity to emergency services centers). These data were combined mathematically to estimate the consequence value for that location. Aggregating societal and environmental values with wildfire risk to arrive at a single consequence value requires defining data considerations and their corresponding weights among diverse datasets, such as proximity to a national park and proximity to a manufacturing hub. The data inputs and mathematical approaches used for consequence analysis are determined in the early stages, following or in conjunction with the development of the WMP.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Quantifying the consequences of wildfire at scales ranging from neighborhoods to a spatial grid provides utility with a graduated perspective on the multifaceted consequences across their service area. Utilizing infrastructure knowledge (including internal private data) to co-locate these spatially varied consequences facilitates the identification of optimal starting points for additional system hardening actions and public outreach to reduce adjacent fire fuel loads. The consequence analysis data also inform where PSPS de-energizations may be appropriate during wildfire-likely weather/fuel conditions, as well as where previous mitigation strategies now allow for continued electricity transmission. Integrating other downstream consequences from irregular power operations, whether directly from wildfires, wildfire smoke, or planned de-energizations, can facilitate the expansion of consequence analysis. For example, the 2023 Lahaina, Hawaii wildfire highlighted the cascading impact of power loss, leading to the inhibition of pumped water supplies and a failure of emergency water supplies for fire suppression. Together, these issues hindered the wildfire response and expanded the impact. Another example is the disruption of fuel supply to Arizona and Nevada via Kinder Morgan's SFPP West Line and CALNEV pipeline during the 2025 Los Angeles wildfires. While the wildfire did not directly affect the pumping station or pipelines, the power outage necessitated a temporary shutdown of the pipelines, resulting in an energy supply disruption. Incorporating associated downstream risks into the analysis and planning can help mitigate them during future events.

Challenges to Implementation: No standard data workflow for consequence analysis yet exists. Following the development of WMPs, there are at least three main challenges to performing consequence analysis. The first is combining numeric values to quantify a location's risk according to factors associated with wildfire, such as infrastructure age, predicted burn probability in a given year (0–100 percent), and the monetary value per fatality (i.e., the value of statistical life). The second challenge is spatial—what value should be used in the analysis for distance from electric infrastructure? Utilities can manage the vegetation in their ROWs, but they cannot control its growth into adjacent public or private land. The third challenge relates to data availability—most utilities lack the technical expertise to update their vegetation fuels data and perform wildfire simulations, instead contracting this work to private industry. Advanced expertise in GIS is also required to integrate societal and environmental data into wildfire simulations. The matter of which geospatial datasets to consider and how to integrate or weight these datasets is often somewhat qualitative. In particular, for utilities with little previous exposure to wildfire, consequence analysis entails increased costs, uncertainty about which best practice is most appropriate, and difficulty determining how to apply the analysis results to alter future operations.

Examples: PG&E likely has the most data-intensive and robust approach, using its Wildfire Consequence Model Version 4 (WFC v4). This consequence model utilizes commercially provided wildfire simulations and developed fire indices, as well as two PG&E-developed wildfire indices (dry wind conditions and predicted destructive indices). Nevertheless, input data and results are changing quickly. Between the development of WFC v3.4 (2022) and WFC v4 (2023), the value of statistical life decreased from $100 million to $12.5 million, and after the addition of models for public egress and fire suppression into v4, the length of overhead primary conductors that must be hardened or undergrounded to mitigate wildfire risk increased by 46 percent (10,000 miles to 14,600 miles) (PG&E, 2025a). In a different context, the USFS Quantitative Wildfire Risk Assessment (QWRA) framework is a spatially explicit methodology used to characterize the predicted threats and potential benefits of fire across a landscape, informing land management decisions. The framework defines and calculates risk as the combination of wildfire hazard and the vulnerability of highly valued resources or assets (HVRAs) to that hazard. While the tool has a more land management focus, one of its core tenets is about HVRAs, which can be ecological, social, or economic features on the landscape that could be affected by a wildfire. Examples include communities, critical infrastructure, water resources, timber, and specific wildlife habitats.

Future Direction: Consequence analysis modeling for electric utilities, in the context of wildfire risk mitigation, needs to shift from static assessments to dynamic, highly granular, and interconnected models that account for cascading system impacts. This includes components that incorporate real-time and forecasted fire spread and impact, modeling the risk-reduction benefit (i.e., reduction in consequence) of various mitigation strategies, connecting actual or forecasted wildfire damage or operational changes to the power grid with its downstream effects on interdependent infrastructure (i.e., other energy services, telecommunications, water supply/pumping, hospitals, transportation signals), and models that incorporate high-fidelity physics to predict specific failure mechanisms (e.g., how high heat and smoke from a nearby fire reduces the electrical insulation strength of the air gap, potentially causing a line to trip (arc-ignition and flashover risk), even without direct flame contact).

3.11 Weather Forecasting and Monitoring

Fire danger is highly localized and evolves rapidly, so accurate, timely weather data are fundamental to utility wildfire preparedness. Fire seasons have also evolved in recent years (Table 1), with an increase in fire-weather days across most of the country (Yu et al., 2023; Donovan et al., 2023; Abatzoglou et al., 2020). Weather conditions, such as high temperatures, low relative humidity, high wind speeds, and low rainfall, can increase fuel dryness, ignition risk, and the rate of fire spread. Weather datasets from stations and satellites are translated into operational intelligence through the development of wildfire risk models or risk alerts and indices, such as the USGS Fire Danger Forecast products (USGS, 2025). Utilities consider location-specific weather conditions when conducting operational management activities, such as prepositioning crews and adjusting EPSS or PSPS settings to mitigate wildfire risk.

3.11.1 Weather Monitoring Infrastructure and Data Collection

Description of Practice: Whether publicly available or privately owned, observed and modeled weather data play a significant role in wildfire preparedness. Weather stations provide information about on-the-ground, real-time conditions to help understand localized wildfire risk. High-resolution weather modeling provides daily to weekly forecasts with regional coverage, enabling the anticipation and preparation for future risks. Access to weather monitoring infrastructure supports operational management, as utilities often assign thresholds to weather conditions to trigger actions that mitigate risk. Monitoring infrastructure includes an expanding workforce of meteorologists focused on improved forecasting and prediction.

Extreme weather conditions can cause damage to transmission and distribution lines and result in system outages. High winds or lightning can cause trees to fall into power lines, and high temperatures can cause power lines to sag and come into contact with objects. Concerning wildfire preparedness, weather data collection and monitoring infrastructure generally do not directly affect transmission or distribution lines, but can indirectly affect the system. Prior to periods of active wildfire events, excessive rainfall can greatly increase vegetation growth in a region. Furthermore, the presence of invasive vegetation species tends to increase fuel loading and intensify wildfires. A heightened fuel load increases ignition potential and affects the spread rate during periods of high wildfire risk. Understanding weather conditions in high-fire-risk districts can enable utilities to target grid sections for system hardening or to implement EPSS and PSPS protocols, which affect both transmission and distribution lines. Other weather-initiated protocols include line de-rating, heightened monitoring, staging patrol/inspection crews, and restrictions on fieldwork.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Weather monitoring infrastructure supports wildfire preparedness through multiple avenues. Government agencies have developed metrics and indices to characterize wildfire risk based on weather data. For example, the NWS uses real-time observed weather station data and short-term (24–96 h) forecasts of weather parameters to issue alerts for RFWs and high-wind warnings, which utilities access for operational use. Additionally, NIFC leverages observations and forecasts to provide national fire-risk outlooks. Weather conditions directly correlate with wildfire risk, so using local data to identify weather-related triggers specific to a utility's wildfire risk profile improves operational settings and strategies, enabling a quicker response. Additionally, understanding seasonal weather conditions, such as wind gusts, can inform targeted asset hardening.

Challenges of Implementation: High-quality weather data are essential for all downstream management decisions and tools. Record gaps or limited spatial coverage of weather data networks, particularly in remote yet high-risk regions, remain a challenge for weather monitoring and associated decision-making. Many utilities have deployed proprietary station networks to address these issues, but this approach is costly and requires ongoing maintenance to ensure reliability. Data streams from large networks require high-performance computing and data storage, often necessitating the involvement of third-party vendors and associated costs and risks. For weather forecasts, the main challenge is uncertainty associated with underlying models and datasets.

Examples: Many utilities (Kittitas PUD No. 1, Tacoma Public Utilities, Idaho Power Company, and NorthWestern Energy) rely largely on public data and/or partnerships with state and federal entities. Larger utilities in the West/Southwest (SCE, SDG&E, Liberty Utilities, SFPUC, and

PG&E) deploy proprietary weather station networks of varying densities, which enable real-time monitoring in high-fire-risk districts. Anza Electric Cooperative has developed partnerships with SCE and SDG&E to share weather data, while Truckee Donner PUD utilizes local weather data from NV Energy and Liberty Utilities. Other utilities (e.g., PG&E, SDG&E, and Pacific Power) make their data publicly available. Bear Valley, Anaheim, Palo Alto, and Trinity PUD use a combination of utility-owned and publicly available data. Utilities in the Midwest and the Northeast (e.g., McCook Public Power District) often rely exclusively on federal data, with little to no proprietary weather infrastructure.

Future Direction: Utilities can leverage publicly available national datasets and indices for high-resolution forecasts that support risk mitigation strategies. Consolidated channels or a platform to standardize and disseminate datasets would support integration by utilities. An example is ingesting data from state or national mesonets, such as the USFS Remote Automatic Weather Stations (RAWS). If desired, deploying private weather stations in complex terrain and high-fire-risk districts increases data availability for wildfire preparedness.

3.11.2 Red Flag Warnings

Description of Practice: NWS issues an RFW when critical weather and vegetation conditions conducive to increased risk of rapid wildfire activity are forecasted within a 12- to 48-hour period. RFWs vary among Weather Forecast Office zones and are defined by interagency operating procedures. Typical triggers of an RFW include prolonged drought and dry fuel conditions, low relative humidity, strong or gusty winds, and the possibility of dry lightning strikes.

For many utilities, an RFW signals fire risk and triggers preventive actions such as EPSS and PSPS, which affect distribution lines. PSPS activation can also include de-energization of transmission lines to prevent potential ignition. The duration and applicable area of RFWs directly influence the duration and scope of these preventive measures, as well as the associated impacts on the system.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: RFWs currently serve as a crucial trigger for land management agencies and utilities to implement enhanced wildfire prevention and response strategies during periods of heightened fire-weather risk. Utilities implement additional precautions and operational limitations during RFW periods to reduce the risk of electrical infrastructure-related ignition. Utilities often limit or defer nonessential field work on overhead energized lines, allowing only critical work related to public safety or fire risk reduction.

Challenges of Implementation: RFWs are not standardized forecasts across the country. RFWs are regional alerts issued according to varying quantitative measures (over 500 unique criteria across all NWS weather forecast offices; Jakober et al., 2023). Some zones use the National Fire Danger Rating System as a trigger; however, this system is limited by sparse underlying observations and is less accurate in areas with steep, elevated topography. Another challenge of implementation is that actual fire risk and conditions may vary locally within weather zones. As a result, some utilities (e.g., Los Angeles Department of Water and Power) use more granular, city-specific “Red Flag Alerts” that differ from the NWS-issued warnings. By contrast, some service areas (e.g., Centralia City Light) have never experienced an RFW, signifying that warnings are not universally applicable to all service areas. In addition, the high frequency of RFW forecasts has desensitized agencies, and many now incorporate RFWs into broader suites of metrics and considerations. As a result, there is potential for utility-caused fire on high-risk days (e.g., Camp Fire in 2018). Utility-caused wildfires have also occurred on days when an RFW was not issued (e.g., the Marshall Fire in 2021).

Examples: Arizona Public Service adopts specific procedures during RFWs, including equipping vehicles with fire-mitigation tools and deferring nonemergency fieldwork. Canby Utility actively monitors the NWS for RFW alerts and increases internal communication to discuss risk mitigation and equip vehicles with fire tools. Silicon Valley Power implements specific safety briefings, conducts daily wildfire patrols, and ensures power line maintenance is performed with lines isolated during RFWs. Central Electric Cooperative uses RFWs as a key data input for its situational awareness tools, which guide its approach to wildfire risk reduction. To circumvent the challenges of utilizing RFWs for wildfire risk, PG&E developed a dry wind conditions index, which accounts for wind speed, 10-hour dry fuel moisture, and relative humidity.

Future Directions: There are three main future directions, categorized by level of effort:

- Low: Upgrading and standardizing RFWs and associated communication.
- Moderate: Incorporating or replacing RFWs with alternative metrics.
- High: Developing novel metrics or models using ML.

The urgent need to reevaluate RFWs and their use by utilities is being addressed by industry leaders through a National Oceanic and Atmospheric Administration (NOAA Regional Integrated Sciences and Assessments team (NOAA, 2025a). Changes will include a standardized, two-tiered warning system designed to reduce over-forecasting. In line with this effort, the NWS Hazard Simplification Project (NWS, 2025) is retooling the alert system and language to better communicate wildfire and other hazard risks. Continued efforts to make RFWs more accessible and applicable to key stakeholders are encouraged. Additional information on RFWs can be found in Appendix A.

3.12 Tabletop Exercises and Training

Description of Practice: Tabletop exercises (TTXs) are discussion- or active scenario-based operational exercises designed to analyze and enhance internal and external coordination in responding to potential wildfire threats (or other emergency event). TTXs provide a simulated environment for practicing emergency procedures, incorporating both functional exercises and full-scale simulations. Functional exercises validate plans, policies, agreements, and procedures, clarify roles and responsibilities, and identify resource gaps in an operational environment. Through functional exercises, utilities demonstrate the ability to successfully execute specific tasks and actions. Full-scale exercises validate an organization’s capabilities in a complex, multiagency environment. TTXs often adhere to principles from programs like the Homeland Security Exercise and Evaluation Program in their management, design, development, and evaluation, and training is conducted in a variety of formats, including classroom instruction, workshops, safety demonstrations, tailboard meetings, and continuing education programs. Training programs ensure that personnel understand their specific duties and responsibilities under the WMP and are aware of safe working procedures, particularly in elevated risk conditions.

System Application: Applicable to transmission systems as well as distribution systems through general utility preparedness.

Risk Mitigation Benefits: TTXs and training ensure preparedness for high-risk situations by familiarizing staff with emergency plans and procedures, including those for PSPS de-energization. Exercises enhance coordination between utility emergency operations centers and external agencies, fostering stronger relationships with emergency response teams and facilitating the sharing of crucial information. TTXs and training are also critical for evaluating and validating procedures, helping to identify deficiencies, areas for improvement, and barriers to implementation, thus providing an opportunity for process improvement. Properly trained staff and contractors are essential for effective vegetation management, asset inspections, and emergency response, all of which directly reduce ignition risks, enhance system reliability, and improve safety.

Challenges of Implementation: Utilities face several challenges in implementing and optimizing TTXs and training, especially within an evolving technological landscape. For example, implementing new models requires significant staff training for users and familiarization for decision-makers to achieve proficiency. Additionally, multidimensional data streams are complex and can be difficult to parse, requiring informed users to validate and implement appropriate tools for rapid decision-making.

Examples: The Los Angeles Department of Water and Power regularly holds “Power System Command and Management Exercises” that provide an overview of critical emergency management systems (the Incident Command System [ICS], the Standardized Emergency Management System [SEMS], and the National Incident Management System [NIMS]). They also participate in drills and exercises with regional and city partners, covering a wide range of topics, from brushfire to grid security exercise scenarios. Puget Sound Energy engages in grid operator training and industry workshops to collaborate with peer utilities and drive continuous improvement. The utility leverages industry best practices and benchmarking to develop situational awareness tools that proactively identify risks. Sacramento Municipal Utility District uses TTXs to enhance coordination, test emergency operating plans, and invite public safety partners to rehearse practices in a simulated environment.

Future Direction: Conducting cross-sectional exercises across multiple utilities and external stakeholders is imperative to ensure streamlined coordination during a wildfire event. Incorporating state and federal emergency agencies into existing TTXs will improve preparedness. Workshops that bring together multiple utility companies can also inform best practices and lessons learned. As new technologies emerge, frequent exercises will support adaptation and effective use.

3.13 Multi-entity Coordination

Description of Practice: Coordination should be a continuous cycle that begins in the pre-event phase, extends through post-event recovery, and then returns to the pre-event phase. Even at the scale of a county or town, such coordination is complicated, as the utility’s infrastructure extends across a spatially fragmented landscape with diverse interests and concerns. This is exacerbated with regional-scale utilities. Such collaboration should leverage previous engagement frameworks developed to reduce wildfire risk in the wildland-urban interface and to construct community wildfire protection plans (Davis, 2025). Recent fires crossing the wildland-urban interface that caused substantial loss of life and property, such as the Camp Fire (2018) in Northern California, the Marshall Fire (2021) in Colorado, the Lahaina, Maui fire (2023), and the more recent Los Angeles area Eaton and Palisades fires (2025) caused a substantial loss of life and property that reinforce now decades-old discussions. The interface fire problem is not just the responsibility of land managers, nor is it the sole responsibility of the electric utility. Many stakeholders must share responsibility for fire management, including local, state, and federal agencies, fire protection agencies, utilities, homeowners, local and regional planners and governing bodies, builders, landscape architects, as well as insurance carriers and mortgage bankers (David, 1990).

Programs and groups, such as the Fire Learning Network, Fire Safe Councils, and Firewise Communities USA, are actively working to engage private citizens and government officials in wildfire-related conversations that empower action (Davis, 2025). These actions would also leverage established practices of system hardening (Section 3.5) and IVM (Section 3.8.2).

Utility-engagement can repurpose how five different community categories are engaged through *Fire Adapted Communities.* Progressing from very rural to urban, farmers and ranchers in *Working Landscape* are highly knowledgeable about the local ecology, prefer person-to-person communication, and want to be active stewards of the land. *Rural Lifestyle* communities are a mix of primary and secondary homes with often complicated ingress and egress, and may establish formal groups, but most communication remains person-to-person. *High Amenity* are communities of secondary homes near outdoor amenities such as ski resorts or national parks, preferring formal collaborative groups leveraging scientific information with more formal communication pathways toward maintaining the aesthetics of wildlands. *Formal subdivision* is defined by the development's spatial extent, with residents from a range of economic and cultural backgrounds often benefiting from outside assistance for fuel reduction and home hardening, orchestrated through homeowner associations. *Commercial* areas are generally accustomed to municipal and emergency services residing in apartments or multi-family units, making it difficult for residents to manage wildfire fuels themselves and requiring communication through a formal network.

System Application: Applicable to transmission systems as well as distribution systems through general utility preparedness.

Risk Mitigation Benefits: Coordination between utilities, land managers, and landowners can reinforce the utility's multifaceted contributions to the community by maintaining a reliable energy supply and helping to reduce a community's wildfire risk (Abrams et al., 2015; Huber-Stearns et al., 2021, 2022). Common utility tasks, such as managing vegetation in infrastructure corridors and maintaining road access, are forms of pre-event wildfire preparation (Figure 2). During a wildfire, managed vegetation corridors can serve as fire breaks, allowing for fast ingress and egress by utilizing the utility's access roads. Utilities also play a critical role in de-energizing lines for when firefighters need to operate in close proximity to power lines, when falling trees or heavy smoke compounds fire risk, and pose safety concerns. In summary, this is a community-wide task that relies on defining needs, objectives, and impacts by communicating and planning for contingencies, and on enabling resilience, which will look different in every place and circumstance.

Challenges of Implementation: Multi-entity coordination can take years to fully engage in actions and planning to reduce an area's wildfire risk. A governance structure needs to be established, and one entity should be designated as the lead/convener. A source of funding to support these efforts will only help lead to its success, but there are often challenges here.

Examples:

- Applegate Valley (Oregon) developed the first community wildfire protection plan in the United States, initiated in 2001; fuels reduction and planning reduced the impact of the 2002 Squire Fire; 24 federal, state, and county agencies now collaborate to reduce the wildfire risk of the region; the Oregon Department of Forestry just provided funds to update the community wildfire protection plan for 2026.

- Xcel Energy in Colorado conducts an annual drill with local fire departments related to scenarios of power line ignitions and response to PSPS.
- NV Energy collaborated with the National Security Council and local fire departments in 2025 to educate residents about fire prevention strategies, evacuation protocols and procedures.
- PG&E pre-positioned firefighter resources near at-risk critical infrastructure in Oct. 2024 during a period of especially high wildfire risk.
- The Electricity Subsector Coordinating Council's Wildfire Working Group is the principal liaison between the leadership of the U.S. federal government and the electric power sector. It is a CEO-led, self-governed organization created to coordinate efforts to prepare for and respond to national-level wildfire threats to critical infrastructure, ensuring the security and resilience of the North American energy grid. Cross-Sector Coordination with other critical infrastructure sectors, such as communications, oil and natural gas, water, and transportation, is imperative to manage interdependencies during a crisis.

Future Direction: Increased coordination among multiple entities can benefit all parties involved. Many of the communication strategies and approaches used by groups such as Firewise Communities USA are directly applicable to discussions between utilities and the communities they serve. As these organizations note throughout their material, "having everyone at the table" leads to the success of these fuel management strategies, and would therefore benefit from having utility representatives in those discussions. Drawing from the recommendations of the 2023 Wildland Fire Mitigation and Management Commission, the Fix Our Forests Act (S. 1462) is a pending, bipartisan bill last updated on October 30, 2025. This legislation provides a comprehensive multi-faceted framework for tackling complex forest management issues by scaling up forest restoration efforts to improve health and reduce catastrophic wildfire risk (Wildland Fire Mitigation and Management Commission, 2023; U.S. Senate, 2025). Key provisions relevant for multi-entity coordination include expediting administrative procedures for planning and permitting, including for utility rights-of-way, authorizing and coordinating grants for community risk mitigation programs, land use planning incentive programs, Good Neighbor Authority, coordination and co-management with Tribes, and adopting technologies to address forest health and wildfire risk reduction.

3.14 Utility Benchmarking

Description of Practice: Electric utilities tend to adopt practices similar to those of their peers and conduct benchmarking exercises to optimize operations. In this benchmarking process, the utility systematically compares its performance metrics, operational strategies, and technologies against those of its peers. The goal is to identify best practices, assess performance gaps, and drive continuous improvement across key areas like safety, reliability, efficiency, and wildfire mitigation. Utility benchmarking can be established as a formal internal process, though it is more commonly conducted by third-party consultants or industry groups. It involves collecting and analyzing data on a wide range of metrics, which are then normalized to account for differences in geography, regulatory environment, customer density, and system size. Common metrics for utility benchmarking in the context of wildfire mitigation include 1) system performance with regard to risk assessment methods, number of utility-caused ignitions, acres burned, and related costs, 2) operational practices, including vegetation management practices and revisit cycles, inspection methods (e.g., ground patrol, aerial, and drone), and the use of enhanced protective equipment, 3) adoption of technologies such as advanced conductors, adaptive reclosers, and real-time weather monitoring systems, and 4) capital and operational expenditures on wildfire mitigation programs and the cost-effectiveness of different measures.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Adopting comparative practices to those used by similar utilities is a powerful strategy for mitigating wildfire risk. It enables utilities to identify gaps in their current wildfire mitigation programs, including where current approaches or implementation actions fall short or do not align with those of other utilities. Similarly, utilities learn from each other's successes and failures, identifying the approaches and technology implementations that have been most and least effective for peers. This helps utilities avoid making costly mistakes and adopt proven technologies and strategies more quickly and strategically, aiding the transition from general best practices to defensible, tailored strategies. Additionally, utilities can prioritize their own budgets and justify high-cost investments, such as undergrounding or implementing advanced conductors, by demonstrating a clear cost-benefit relationship supported by industry data.

Challenges of Implementation: Despite the benefits of utility benchmarking, implementing effective comparative practices can be a significant challenge. Utilities often employ different data collection methods, accounting systems, and IT infrastructures, which can pose challenges for collecting and normalizing data consistently and comparably. Thus, to overcome these interoperability challenges, comparative approaches may need to be more generalized. Furthermore, no two utilities are exactly alike. Differences in geography, terrain, ecotypes, meteorology, customer density, regulatory requirements, and infrastructure age can make direct comparisons misleading. Utilities may be reluctant to share sensitive performance data, unless compelled to do so by regulatory requirements, especially if these data reveal weaknesses or put them at a competitive disadvantage. This can hinder the quality and depth of the comparative analysis, again potentially necessitating that some comparisons be more generalized. Additionally, formal benchmarking processes can be expensive and require significant internal resources to collect, prepare, and analyze the data, although they can also be kept internal and used in a more qualitative manner.

Examples: Many utilities actively utilize benchmarking or participate in collaborative forums to compare their wildfire mitigation strategies, performance metrics, technologies, and costs against those of their peers, both nationally and internationally. California's investor-owned utilities and smaller entities provide an effective model—these utilities frequently engage in structured joint benchmarking, often focusing on metrics, practices, technology effectiveness, and cost comparison. Other state-level organizations, such as the Oregon Wildfire Electricity Collaborative (via the Oregon Public Utility Commission) and the Washington Utility Wildfire Mitigation Workgroup (via the Washington State Department of Commerce), provide resources from planning and mitigation tools to sharing of best practices. Organizations such as the Centre for Energy Advancement through Technological Innovation (CEATI), EPRI, and the North American Transmission Forum also provide opportunities to explore objectives similar to those of the California joint investor-owned utility working groups and other state-level organizations. The International Wildfire Risk Mitigation Consortium (IWRMC) has developed a maturity model that enables utilities to assess their current wildfire risk mitigation capabilities across physical assets, planning and operations, maintenance capability, and communications (E Source Companies, 2025). This baseline provides a means for identifying areas for future improvement. Furthermore, this model standardizes concepts and terminology across various utilities, enabling cross-utility benchmarking and tracking progress over time, as well as peer-to-peer processes and system evaluations. Many utilities also conduct an annual WMP maturity review, benchmarking their practices against those of other utilities in the WMPs.

Future Direction: Utility benchmarking will be driven by greater data availability and more advanced analytical tools. For example, AI/ML will enable the analysis of a wider array of unstructured data—such as overhead imagery, real-time weather feeds, and reported outages—to create more nuanced and accurate risk profiles. Industry-wide efforts to create standardized data formats and sharing platforms will make it easier for utilities to contribute and access comparative data, thereby overcoming the challenge of data incompatibility. Utilities should be given stronger incentives to share data, even if it is done under established data controls that prevent it from becoming publicly available. This would enable more systematic, tailored improvements to systems and operations. Comparative practices will need to move beyond a single focus on wildfire to a more holistic view of grid resilience, including a utility's performance in mitigating risks from severe weather, geophysical events, cybersecurity threats, and other relevant hazards.

3.15 Customer Engagement and Planning

Description of Practice: Customer engagement and planning in wildfire mitigation involves approaches to inform, educate, and collaborate with customers, local and state entities, key community leaders, and other organizations. These approaches include stakeholder identification (public safety partners, local governments, critical facilities, Tribal entities, community-based organizations, and individual customers), public education promotion, system operation awareness, resources, and multichannel communications to best enable reaching all stakeholders. Educating the public and raising awareness requires engaging the community to disseminate information about utility wildfire prevention efforts. Engagement should also utilize diverse channels for communication, such as websites, social media, phone calls, text messages, and existing community infrastructure. By engaging customers and incorporating proactive planning, utilities can anticipate the impacts of wildfires and potential outages on critical loads and service areas. These insights inform grid topology optimization, de-energization strategies, and restoration efforts, enhancing reliability and resilience.

System Application: Applicable to transmission systems as well as distribution systems through general utility preparedness.

Risk Mitigation Benefits: Effective customer engagement and planning improve public safety by enhancing community resilience and minimizing the impact of service interruptions. By understanding wildfire risks and utility actions, residents can be empowered to take preparedness actions. These actions also foster collaboration and partnerships among local stakeholders to provide mutual support and collaborative response during emergencies.

Challenges of Implementation: Challenges associated with customer engagement include difficulty establishing clear and coordinated communication across platforms to avoid conflicting messages. Additionally, utility outreach plans must remain flexible to adapt to shifting community needs and be diverse enough to reach populations that speak different languages or that face other communication barriers.

Examples: NorthWestern Energy incorporates public communication and outreach as a critical part of its WMP. Its incident command system (ICS) is tasked with coordinating with public safety partners and community managers. Portland General Electric focuses on building long-term relationships to understand community needs through multiple engagement sessions. Sacramento Municipal Utility District uses stakeholder outreach during its WMP preparations.

Future Direction: Utilities should continue efforts to ensure that communication with customers is targeted, accessible, diverse, and effective, particularly before a wildfire event. Through peer-to-peer engagement including annual forums or webinar series, utilities can share lessons learned and best practices to better educate customers and improve wildfire preparedness. Utilities can also use data-driven decision-making by leveraging performance metrics to identify deficiencies in customer-related initiatives.

4.0 Resilience as Graceful Extensibility (During Event)

Best practices in this section are actions that may occur under a highly probable near-term wildfire start and associated heightened preparation and avoidance actions, or after a wildfire event begins and the monitoring and response. These best practices are outlined to support decision-making that reduces ongoing risk and minimizes impacts on power systems. These real-time or near-real-time efforts occur on the order of seconds to hours, either enabling decision-making or triggering automated actions.

4.1 Enhanced Situational Awareness

Description of Practice: Situational awareness is a comprehensive understanding of the working environment, including real-time wildfire risk and weather, fuel, and system conditions. It encompasses multimodal data inputs, methods, and analytics to improve power system monitoring, fault and ignition detection, risk awareness and forecasting, trend monitoring, resource detection and allocation, and intuitive visualization, enabling holistic awareness of the system and environmental conditions. This kind of actionable intelligence provides a foundation for informed decision-making, operational response, and the ability to strategize how conditions during an event may change in response to various factors. It also extends to understanding the extent and degree of damage for timely response and recovery purposes. Enhanced situational awareness during an event may rely on continuous monitoring of conditions throughout many years and varying conditions to understand behavior and risk trends.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Enhanced situational awareness facilitates collaborative responses and helps improve operational and strategic decisions to best enhance safety and minimize impact as much as possible. It is an integral concept in emergency management. Capabilities such as system fault detection, smoke sensors, camera systems, and overhead observation via high-resolution satellite or UAS imagery may help provide timely responses to hazard management teams. By enabling earlier detection of ignition starts, there is a better chance of minimizing wildfire impacts.

Challenges of Implementation: Similar to other best practices, enhancing situational awareness faces implementation challenges that are largely related to resource limitations—specifically, insufficient staff, staff expertise, and resources. This can be especially impactful for smaller utilities without the aid of grants or cooperatives. Power system monitoring infrastructure, including sensor networks, high-resolution cameras, overhead observation, and automated devices, can be costly. Additionally, publicly available weather data may lack granularity or real-time information for informed decision-making.

Examples: Many utilities are actively implementing or enhancing their situational awareness capabilities. To improve upon the availability of public weather data, some utilities (e.g., Anaheim Public Utilities, Arizona Public Service, Bear Valley Electric Service, Hawaiian Electric, Horizon West Transmission, Idaho Power, PacifiCorp, PG&E, Sacramento Municipal Utility District, SDG&E Company, and Xcel Energy) are deploying their own networks of weather stations or expanding existing networks to provide more granular, real-time data on conditions like wind, temperature, humidity, and fuel moisture. Other utilities, such as Hawaiian Electric, PG&E, SDG&E, and Xcel Energy, are actively using commercial or cooperative camera systems with AI processing for wildfire detection, in addition to streaming multimodal sensor data into control rooms or emergency operations centers.

Future Directions: The future of enhanced situational awareness is focused on greater automation, integration, anomaly detection, and intelligence through recommended actions or after-action analysis. Post-event retrospective analysis of operational efficacy can enhance real-time situational awareness in subsequent events. AI/ML is already playing an increasingly central role, not just in processing data but in providing autonomous system alerts. A practical example is using AI/ML to analyze a combination of wind speed data, vegetation moisture data, and live camera feed images to provide human-in-the-loop recommendations to operators. With further training, the system can learn nuances and automatically adjust protective relay settings on a circuit in real time, with minimal human intervention. The use of digital twins will become more sophisticated, allowing utilities to run complex simulations of different scenarios—such as a specific fire path—to test the effectiveness of their mitigation strategies in both planning and real-time operations. Utilities are expected to integrate even broader data, including regular satellite imagery for assessing soil moisture and vegetation health, automated UAS regular and incident inspection analysis data, deep learning–driven meteorological forecasts, and even social media feeds to obtain a more comprehensive picture of what is happening on the ground. There will be an increased need, perhaps driven by the need for greater cost efficiency, for regional data-sharing platforms where utilities, state agencies, and fire authorities can share a common operating picture, improving overall coordination and effectiveness of fire response across large geographic regions. In the broader context of holistic resilience, enhanced situational awareness will need to evolve to address a broader range of threats, including severe weather events, cybersecurity attacks, and physical security risks, creating a truly adaptive, resilient, and interconnected grid.

4.2 Monitoring Tools and Assessments

Monitoring tools and assessments support early detection, reducing response time, suppressing fire growth, and minimizing damage. Monitoring tools use ground-based instruments and networks, satellite remote sensing, and other advanced technologies to detect and track the progression of active fires in real time. Some monitoring systems use predefined thresholds to isolate changing conditions. Thresholds of key risk indices that trigger various decision-making actions will likely need to be unique to the specific geography of the service territory. The use and long-term validation of a set of utility-selected thresholds will take time to realize, and incremental adjustments are expected. Assessments such as fire behavior modeling and asset threat proximity analysis process data collected by tools to characterize fire behavior and potential impacts, providing actionable intelligence for operational decision-making. For utilities, these capabilities are crucial for coordinating resources, adjusting grid operations, and protecting assets. Monitoring systems often integrate multiple tools to provide a comprehensive assessment of vulnerabilities during a wildfire.

4.2.1 Meteorological Data and Risk Modeling

Description of Practice: Meteorological data can be retrieved from ground-based weather station networks, satellite remote sensing, and observation-based reanalysis forecast datasets for use during escalating or active-event conditions. Wind, humidity, temperature, and fuel moisture datasets are used to monitor wildfire risk and spread, and near-real-time data can be ingested into forecasted fire behavior and spread models to further assess risk scenarios and support more strategic decision-making. Many utilities employ dedicated meteorology teams to translate weather data, improving real-time situational awareness and operational decisions, where others rely on the public issuance of NWS RFWs and forecasts with simple environmental thresholds to guide operations.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: During a wildfire, continual assessment of hazardous weather conditions, such as wind, relative humidity, lightning, and precipitation patterns, enables utilities to predict likely impacts more accurately, thereby better positioning repair crews, de-energizing lines, adjusting relays/reclosers, monitoring within high fire threat districts, and protecting system critical or more vulnerable assets. A secondary benefit is that monitored data can be collected to validate and refine wildfire prediction models and tiered operational thresholds, thereby better tuning and strengthening preparedness and response in the future.

Challenges of Implementation: Effectively accessing and aggregating high-quality weather data from diverse sources —including local stations and satellite-based technologies —requires robust data processing infrastructure and expertise. Another challenge is that weather station coverage can be sparse, and satellite coverage may not be as timely or accurate as an in situ station. However, deploying and maintaining proprietary weather station networks is costly, thereby requiring careful planning.

Examples: Many utilities (e.g., Anaheim Public Utilities and Cowlitz PUD) leverage networks of both utility-owned and publicly available weather stations to assess localized fire-risk conditions. Anza Electric Cooperative and Umpqua Indian Utility Cooperative also integrate NOAA and USFS risk forecasts into their monitoring operations. For broader coverage, NOAA and National Aeronautics and Space Administration (NASA) satellite technologies (used by SCE and Tacoma Power) enable fire confirmation and tracking. Portland General Electric has a direct partnership with NASA FireSense, which provides a suite of wildfire detection and monitoring tools that leverage weather and satellite data. An advanced approach to monitoring wildfire risk is to employ dynamic risk models. For example, SDG&E developed an AI model that incorporates weather station and satellite data to simulate fire behavior and pinpoint high-risk grid zones for carrying out PSPSs. Other utilities (e.g., Idaho Rocky Mountain Power Company and San Francisco Public Utilities Commission) access weather station data, cameras, and commercially generated wildfire risk maps.

Future Direction: Multiscale monitoring systems that combine data sources like utility-owned weather stations with AI-driven models are considered state-of-the-art. Simpler approaches, such as accessing publicly available data and tools, can also strengthen monitoring capabilities to improve real-time risk analysis. USFS Remote Automatic Weather Stations' (RAWS) and other network weather station data and/or NOAA/NWS alerts can inform fire-weather risk. To monitor fuel characteristics, NASA, NOAA, and the European Space Agency satellites provide high-cadence data that enables vegetation condition assessments. The USFS Wildland Fire Decision Support System (WFDS) includes fire-spread probability modeling, relative risk rating, and strategic assessments to support risk-informed interagency operations. Although the system was not initially designed for operational use by utilities, access to it is beneficial for coordination with government agencies during a wildfire. Similarly, the USDA/USFS Suppression Difficulty Index was designed to provide agencies with information on the level of effort, hazard extent, and awareness during firefighting. However, this index can be incorporated into a utility’s existing monitoring framework to offer insight into wildfire spread and behavior.

4.2.2 Visual Surveillance Systems

Description of Practice: Visual surveillance systems use optical or imaging sensors to observe, detect, and track wildfires in real time. Systems generally include fixed or fixed-rotating visible or visible + infrared cameras. Furthermore, mobile sensors on UAS platforms with true-color (visible light), multispectral, and mid- or long-wave thermal infrared technologies are useful for regular and on-demand detailed system observation. Visible-light or infrared cameras can be mounted on utility poles and towers. UAS provides aerial imaging and mapping over the grid that can be manually or automatically operated, per Federal Aviation Administration (FAA) guidance, and where nearby or interfacing with easements or adjacency to Federal lands, using a Blue UAS cleared airframe and components. These systems detect system anomalies (e.g., objects on or below conductors), smoke, flames, or heat signatures, enabling early detection, situational awareness, and emergency response.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Visual surveillance systems detect early wildfire ignitions and potential fault causes in high-risk areas with critical infrastructure. Visualizing wildfire spread and smoke during an event enables rapid response and the prioritization of resources for the strategic deployment of equipment and personnel.

Challenges of Implementation: Visual technologies used for monitoring have several operational limitations, including signal disruption from smoke or clouds and obscured views due to dense tree canopies. Line of sight can be obscured by smoke, haze, and clouds; however, under new FAA rules for UAS operation, it is possible to operate over the ROW under non-line-of-sight conditions, but it will also require the right mix of sensors to be effective in detecting through thick smoke. Camera sensors without infrared capabilities cannot perform nighttime monitoring. LiDAR systems are active sensing units that capture objects as 3D point clouds, with a signal return intensity for each point. These systems can operate day or night and through cloud and smoke, though due to the volume and complexity of data processed, it is currently difficult to process in near real-time. UAS operation through federal easements or ROW-adjacent lands will require that such use be incorporated into the Operations and Maintenance Plan, and that operators have an FAA pilot license, UAS registration, and BLUE UAS cleared systems. The USFS and BLM, for example, have established requirements, and interested entities may need to apply for such a ROW grant. Vegetation and terrain can further challenge the capture of visual surveillance systems, and fixed cameras can only monitor the region within their field of view, though many camera systems allow and perform a regular 360° rotation.

Examples: High-resolution cameras with AI or infrared capabilities are revolutionizing fire detection. ALERT is added to watchtowers and communication towers across many western regions to provide line-of-sight monitoring. Hawaiian Electric Company deploys AI-enabled cameras near its infrastructure using ALERTWest software for early detection of fires or smoke. Other examples include Central Lincoln PUD using the ALERTWildfire network and Anaheim Public Utilities using infrared camera networks from ALERTCalifornia. Commercial infrared camera systems are accessed by a range of providers, including PG&E, CORE Electric Cooperative, Austin Energy, and Arizona Public Service. An alternative or in addition to pole-mounted cameras for monitoring environmental conditions are UAS with optical or thermal cameras for targeted surveillance. Sacramento Municipal Utility District and Trinity Public Utilities District use UAS to monitor emerging fire fronts, inspect infrastructure damage, and assess vegetation encroachment on power lines.

Future Direction: Utilities can coordinate with other regional entities to create a cooperative camera network with advanced detection features and automated notifications to improve situational awareness and responsiveness. Central Lincoln PUD, Ukiah Electric Utility, and Portland General Electric plan to expand their surveillance systems with additional fire detection cameras, UAS-based sensing, and lidar data. High-cadence, low-latency satellite imaging technologies focused on fire and smoke detection are improving with newly designed constellations that will become more widely available over the next five years. This is particularly beneficial for remote and hard-to-access regions. To leverage existing infrastructure, older cameras slated for investment can be upgraded with modern technology, such as infrared or AI capabilities, to improve anomaly detection. Utilities can also partner with established cooperative networks for new installations, maintenance, and monitoring to help reduce costs. Camera systems benefit a wide range of stakeholders, not just utilities. To share resources, utilities can also partner with state or local entities for UAS patrols, which is a strategy adopted by Redding Electric Utility.

4.2.3 Grid Sensor Networks

Description of Practice: Sensor networks are interconnected systems of devices distributed across the grid to collect and transmit operational data. Sensors are generally mounted on utility infrastructure such as lines or poles and can be wired or wirelessly connected. This enables continuous collection to detect anomalies such as arcing, conductor faults, and downed conductors, enabling quick detection and rapid response. On transmission lines, sensors can also measure sag and vibration, which can be used to identify increased ignition risk due to vegetation contact or strong winds. Radio frequency sensors are mounted directly onto both distribution and transmission lines.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Sensor networks improve the monitoring of asset health and the identification of anomalies and failures, limiting service interruptions and physical damage, and providing timely awareness of potential ignitions. For example, remote sensors enable automatic de-energization of lines on fault (EPSS) and limit the duration of service interruptions. Sensor technology supports effective action and coordination with emergency management agencies and responders.

Challenges of Implementation: Sensor deployment in remote locations involves not only installation expenses but also logistical and maintenance challenges. Similar to visual surveillance systems, sensors have sparse coverage and so must be placed strategically. Without visual guidance, understanding sensor output can be challenging because anomalies must be interpreted to quickly and automatically identify system issues during events. These alerts bring a human-in-the-loop for review and action. Beyond the sensors themselves, the logistics of transmitting data from sensors can be a challenge in remote locations or over complex terrain. Another potential challenge arises from potential cybersecurity vulnerabilities associated with the continuous data streams in SCADA-based grid sensor networks.

Examples: Utilities are implementing sensors through systems such as SCADA and commercial acoustic monitoring systems for real-time grid and asset monitoring. SCADA provides broad, centralized control, facilitating real-time, automated operational command through remote control of substations, transformers, and circuit breakers (SDG&E, Lakeview Light & Power, and Centralia City Light). Commercial acoustic monitoring systems were piloted by PG&E and will expand to Puget Sound Energy. These systems provide localized monitoring of abnormalities in grid sections through pole-mounted, solar-powered devices. Sensor networks can also integrate advanced radio frequency sensors to detect anomalies, faults, or cable degradation (e.g., SDG&E). Sensors are often a component of early fault detection systems, which proactively analyze and identify grid risks. Early fault detection systems have been a valuable monitoring tool for both SCE and Portland General Electric. Other utilities, such as PG&E and Glendale Water & Power, plan to incorporate early fault detection systems into their existing systems.

Future Direction: Utilities that use sensors via SCADA or other systems can improve wildfire monitoring by analyzing sensor output to identify patterns consistent with ignition and assess their specific risks. Processing network data that has already been collected can enhance real-time capabilities and, depending on the utility, may provide additional data for active-event situational awareness, but may also replace visual systems.

4.2.4 Overhead Remote Sensing

Description of Practice: Overhead remote sensing, via aerial (plane, helicopter, or UAS) or satellite platforms, is increasingly used by utilities and other land managers to improve situational awareness by detecting wildfire ignitions, tracking fire progress, monitoring fuel and weather conditions, and providing up-to-date information for use in fire behavior models. These capabilities are largely provided by third-party organizations specializing in remote sensing services (e.g., government agencies, non-governmental organizations, and engineering firms). The use of overhead remote sensing for wildfire applications, particularly via satellite imagery, has expanded in recent years due to advances in sensor types (or “modalities”), sensitivity, spatial and temporal resolution, and the incorporation of AI/ML into the analysis of satellite imagery. In addition, the affordability of satellite-based remote sensing has improved dramatically due to the downsizing of satellite technology, enabling the development of global-scale, high-revisit satellite constellations. The result is the ability to provide high-resolution, high-frequency global coverage of conditions associated with active wildfires and their risk factors, such as weather and fuel moisture.

Overhead sensors generally fall into two types—active and passive—that can measure various wildfire-related phenomena at different times of day or night and under different weather conditions. Active sensors emit their own source of energy (e.g., microwaves or lasers) to illuminate the Earth’s surface and then measure the reflected signal. By contrast, passive sensors measure solar energy that is reflected from the Earth’s surface. As such, most passive sensors collect data during the day, and their application is limited by atmospheric conditions that can obscure surface visibility, such as clouds and dust. An exception is passive sensors that measure energy in the nonvisible portion of the electromagnetic spectrum (i.e., mid- to long-wave infrared and thermal infrared), allowing them to be operated at night. By contrast, active sensors, like those that use synthetic-aperture radar (SAR), can operate day and night and have a waveform that is less affected by atmospheric conditions, making them “all weather” capable, though the information collected and the corresponding analysis and insights from these sensors are different from an optical passive sensor.

Despite the limitations posed by atmospheric obscurities, passive sensors remain the primary tool for overhead remote sensing of wildfire-related phenomena because they provide direct measurement of heat and infrared energy. This capability makes passive sensors better suited than active sensors for distinguishing recently burned areas from actively burning areas, measuring burn severity, and assessing vegetation-related differences in fuel conditions. Active sensors, such as synthetic-aperture radar and lidar, are designed to measure structural characteristics of the Earth's surface, including ground, vegetation, and human structures; thus, they can provide indirect measures of wildfire-affected areas (e.g., changes in vegetation height or biomass density, structural damage, or gradual or sudden erosion or other landform changes). The applicability of active sensors for assessing wildfire impacts is improving, thanks to recent advances in active sensor technology and analytics, which remain active areas of research. In general, the capabilities of passive and active sensors for monitoring active wildfires or assessing post-fire impacts are seen as complementary and can be used in tandem to enhance situational awareness.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Overhead remote sensing, particularly from satellite platforms, can greatly improve utilities' situational awareness of active wildfire events by providing near-real-time, high-resolution data across entire service territories, including remote, difficult-to-access areas. The availability of multiple modalities, or sensor types, also supports the creation of diverse streams of information pertaining to wildfires, including early warning signs, fire progression, burn severity, fuel and weather conditions, smoke density and movement, and firefighting activity (via detection of retardant applications and fire breaks). The data collected from these systems provides an important current system state to feed short-lead fire spread forecast models.

Challenges of Implementation: Overhead remote sensing faces limitations in atmospheric visibility, spatial and temporal resolution, and accessibility and usability for utilities and other stakeholders. Cloud and smoke cover can obscure visibility for passive sensors, although to a lesser degree for passive sensors that detect non-visible energy (microwave or infrared), where active fire events can be detected. Active sensors are less affected by atmospheric conditions, but they are less effective and less mature than passive sensors for wildfire risk assessment. The spatial and temporal resolution of overhead imagery are important considerations for assessing wildfire risk and activity—satellite imagery is better suited to providing large-area, high-cadence information, whereas aerial imagery is better suited to providing local-area, low-cadence information. However, the rapid growth of commercial global-scale satellite constellations offering near-real-time monitoring and the expansion of wildfire-related remote sensing capabilities being developed by the scientific community will expand the applicability of satellite-based remote sensing for assessing wildfire risk. Ongoing reductions in the latency of publicly available satellite data (i.e., delays between when images are acquired by a satellite and when analysis-ready data become available to end users) are also greatly improving the value of these data.

Historically, the accessibility and usability of overhead remote sensing technologies have posed challenges for utilities and other decision-making stakeholders, as this is a specialized field that often GIS and engineering staff don't have, specialized software to evaluate and process data, computing barriers to analyze and digest large volumes of imagery, and the high cost associated with rigorous remote sensing workflows. However, these obstacles are becoming less problematic as more cloud-based decision-support platforms and open-source image processing libraries automatically ingest, analyze, and disseminate remote sensing products to end users.

The applicability of overhead remote sensing for assessing wildfire risk to transmission or distribution infrastructure depends largely on the platform. Satellite-based remote sensing is better suited for assessing wildfire risk to transmission infrastructure because of its large geographic scale, which sometimes includes remote areas. In addition, the spatial resolution of most publicly available satellite data relevant to wildfire monitoring ranges from 10 m to 2 km (measured from the pixel center to the adjacent pixel center), making these data appropriate for assessing large-scale wildfire risk to transmission infrastructure. Some commercial satellite sensors offer higher spatial resolutions (<1 m) and may be applicable to wildfire risk assessment for distribution systems; however, the availability of commercial imagery for a given area of interest may be limited because these systems are typically task-oriented (i.e., not always collecting) and based on user demand. Aerial remote sensing systems are applicable to assessing wildfire risk to transmission and distribution infrastructure because they typically have very high spatial resolution (~5 cm and greater) and can image remote areas. However, aerial remote sensing systems have more limited geographic and temporal coverage than satellite systems, making them better suited for targeted investigations.

Examples: Key examples of national-scale overhead remote sensing applications for monitoring wildfire activity in the United States include NASA's Fire Information for Resource Management System (FIRMS), the NIFC's Enterprise GeoSpatial Portal (EGP), Wildland Fire Open Data, InciWeb front-end interface, NOAA's Hazard Mapping System, Pacific Northwest National Laboratory's RADR-Fire system, and the European Global Wildfire Information System (GWIS). Application developments, such as the openly available WatchDuty, provide an easy-to-use synthesis of publicly available imaging data, coupled with observer data and other data insights. Some of the operational products noted here are actively used in web-based or mobile apps for wildfire monitoring, often in conjunction with other data sources, such as on-the-ground photographs, communications, and other mapping data.

NASA FIRMS distributes U.S. and worldwide near-real-time active fire data that are based on imagery acquired by multiple sensors, including the moderate resolution imaging spectroradiometer (MODIS) aboard the Aqua and Terra satellites and Visible Infrared Imaging Radiometer Suite (VIIRS) aboard the S-NPP, NOAA-20, and NOAA-21 satellites (NASA, 2025). The primary products from FIRMS are thermal anomaly, or "hot spot," detections from the MODIS and VIIRS sensors, although the system includes other feeds of ancillary wildfire-related data, such as active fire locations tracked by the U.S. and Canadian governments, thermal anomalies detected by the Geostationary Operational Environmental Satellite (GOES) geostationary satellites, dynamic true- and false-color satellite imagery from MODIS, VIIRS, Landsat 8/9, and Sentinel-2, normalized burn ratio data from Landsat 8/9 and Sentinel-2 satellites, and satellite-derived smoke/aerosol index data. FIRMS users can receive email alerts and updates, view online maps, and consume analysis-ready data through web services or direct download.

NIFC's EGP (NIFC, 2025d) and Wildland Fire Open Data (NIFC, 2025e) systems distribute current and historic U.S. fire perimeter data, much of which are derived from aerial remote sensing. The number of remote sensing assets at NIFC's disposal, however, is restricted by the scope of geographic coverage, resulting in an inability to fulfill approximately half of all mapping requests. The EGP platform aims to provide NIFC and other members of the wildfire management community with access to up-to-date wildland fire situational data, and is not tailored for use by utilities. However, some applications and products within the EGP may be useful to utilities, particularly for informing PSPS activities. The Wildland Fire Open Data system is publicly available and tailored for a broader user base.

NOAA's Hazard Mapping System contains many of the same active fire satellite-based remote sensing products as NASA FIRMS, including MODIS, VIIRS, and GOES thermal anomalies. Additionally, the Hazard Mapping System contains thermal anomaly data from NOAA's

Advanced Very High Resolution Radiometer satellite and smoke detection data derived from daytime GOES true-color imagery (NOAA, 2025b).

The Global Wildfire Information System (GWIS) is a joint initiative of the European-led Group on Earth Observation and Copernicus work programs. Its aim is to bring together existing sources of information on fire effects and regimes at a global level (GWIS, 2025), much of which is derived from overhead remote sensing. As such, the initiative includes partner organizations from many countries worldwide, including U.S. government agencies (NASA and NOAA) and universities. The GWIS contains five web-based applications. The first is a current situation viewer that provides fire danger forecasts up to 10 days in advance, 1-day lighting forecasts, and near-real-time information on active wildfires. The second application is a current statistics portal that provides national-scale information on the evolution of the current fire season. The third application provides a historical overview of fire regimes at the country and sub-country levels. profile, long-term fire-weather forecast, and data and services portal.

Future Direction: Overhead remote sensing supporting active wildfire monitoring and adjacent conditions to support wildfire forecast modeling will continue to improve with the development and operation of wildfire-focused satellites such as the nonprofit Earth Fire Alliance's FireSat, Canada's WildfireSat, and commercial offerings from Germany-based OroraTech. These systems are being designed to provide high spatial resolution global collections of wildfire events at least every 20 minutes. This kind of observation allows for enhanced situational awareness and the ability to provide rapid refreshes on wildfire spread forecasts, given the latest information. Further, these sensors are equipped with tools to assess vegetation stress and soil moisture conditions, which are highly valuable for wildfire spread forecasts. On the receiving side of the satellite imagery collections, the processing of streams of data requires scalable systems to process the imagery, extract the wildfire characteristics, such as burned area, intense heat/fire front, and spot fires, and make products easily available in common formats for consumption, which will allow for wide use by utilities.

4.3 Adaptive Grid Operations

Adaptive grid operations during wildfire events refer to a system-wide approach in which the electric grid dynamically and intelligently adjusts its operations and protocols in real time in response to evolving environmental conditions and risk factors. This goes beyond localized device settings and represents a coordinated, large-scale strategy that prioritizes safety and risk reduction. This strategy is an evolution of the enhanced situational awareness described previously and involves taking the insights gained from data and acting on them automatically or semi-automatically across a wide area. Practices implemented during an event may include activation of dynamic protective settings, system reconfiguration, targeted PSPS actions, and integration and coordination with fire management agencies.

4.3.1 Protective Equipment, Device Settings, and Fast-Trip Systems

Description of Practice: During the in-event phase of wildfire conditions, protective equipment such as relays, reclosers, and sectionalizers plays a critical role in preventing ignition from electrical infrastructure. By applying specially configured device settings, utilities can adapt protection schemes to address the heightened risk profile of fire-prone periods. In practice, this means enabling fast-trip, or "instantaneous trip," modes when high winds, low humidity, or elevated fire-weather indices are observed. Unlike normal operating conditions, where time-delayed reclosing is permitted in order to maintain service continuity, the in-event phase prioritizes rapid fault clearing and immediate line de-energization to eliminate potential ignition sources. For example, a momentary conductor clash that might otherwise trigger a brief outage can instead be detected and isolated within milliseconds, preventing sparks from contacting dry vegetation. This proactive strategy significantly reduces the likelihood of ignition, supports situational awareness, and complements other emergency wildfire mitigation actions.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: During the in-event wildfire phase, protective equipment with fast-trip functionality provides critical risk mitigation by significantly reducing the time a fault remains energized. Under normal operating conditions, protection systems may allow short-term delays or multiple reclosings to preserve service reliability. However, during periods of extreme fire danger, these same strategies can increase the likelihood of sustained arcing or prolonged contact between an energized conductor and surrounding vegetation. By shifting to fast-trip settings, utilities can detect and address faults almost instantaneously, eliminating conditions that could lead to sparks, molten metal, or hot particles.

This rapid response not only constrains fault energy and duration but also mitigates the risk of cascading failures, such as conductor breakage or pole-top fires, which can exacerbate wildfire ignition hazards. By minimizing arc exposure, these adaptive in-event fast-trip operations can safeguard assets located adjacent to the arc source. Specifically, they lower the likelihood of secondary equipment damage and reduce the potential for spread of fire from expelled debris, sparks, or energized contact. A key strength of this approach lies in its adaptive character. These settings are selectively activated during periods of elevated fire risk, enabling utilities to dynamically calibrate protection schemes in response to prevailing environmental conditions. When integrated with complementary in-event strategies, including sectionalizing and adaptive reclosing, fast-trip deployment contributes to a coordinated protection framework. Together, these measures enhance the grid's ability to mitigate wildfire threats while maintaining operational oversight and preserving resilience under extreme conditions.

Challenges of Implementation: Deploying fast-trip and adaptive protection schemes during wildfire events poses several operational challenges. One of the primary challenges is the potential increase in outage frequency and service interruptions for customers, particularly in rural or radial networks, where limited redundancy constrains the ability to reroute power flow to customers downstream of the affected point following a trip. Unlike urban systems with meshed topologies, which can restore supply through a topology reconfiguration, rural feeders may experience extended outages, raising concerns about reliability and service quality. This trade-off between wildfire risk reduction and service reliability for customers is a central challenge for utilities.

Another difficulty arises from the need for seasonal or real-time adjustments to device settings. Protection parameters must be carefully calibrated to reflect dynamic fire-weather conditions, requiring integration with accurate forecasting tools that capture variables such as wind speed, humidity, and vegetation dryness. Inadequate or overly conservative adjustments may either fail to mitigate ignition risks or result in unnecessary tripping. Moreover, the operational complexity increases when coordination is needed across multiple devices, substations, and regions, often requiring advanced communication and automation capabilities. Typically, utilities aim for optimized coordination that prevents over-tripping or overly conservative operation. Together, these challenges underscore the importance of adaptive strategies supported by robust situational awareness, forecasting accuracy, and customer engagement to balance safety with reliability.

Examples: PG&E's EPSS enables sub-0.1-second tripping during RFWs. Utilities such as SCE and PG&E have actively implemented or considered advanced fault-management technologies—including rapid earth fault current limiters, open phase detection, and early fault detection as part of their wildfire mitigation and grid safety programs (SCE, SDG&E, 2025; and PG&E, 2025b).

Future Direction: Future advancements in wildfire-resilient grid protection can focus on adaptive protection schemes that integrate live weather conditions, information on the amount of affected vegetation, and asset health data to dynamically adjust trip thresholds in real time. The deployment of line-monitoring sensors, combined with predictive analytics, can further enable the early identification of circuits that are at elevated risk, thereby preventing fault initiation. During in-event operations, these adaptive systems can coordinate with dynamic line rating (DLR) and sectionalizing strategies to minimize cascading disruptions. In the post-event phase, automated fault diagnostics and accelerated restoration analytics will enhance system recovery while continuing to inform future risk-aware protection designs.

4.3.2 Adaptive Reclosers

Description of Practice: Adaptive reclosers represent an evolution of conventional recloser technology, introducing the capability to dynamically modify reclosing behavior on the basis of prevailing wildfire risk conditions. Unlike standard devices that follow preset reclosing sequences irrespective of external threats, adaptive reclosers incorporate risk-aware decision-making. For instance, under elevated wildfire risk scenarios characterized by high winds, low humidity, or dry vegetation, they may disable reclosing entirely to prevent reignition following a fault. Conversely, under normal or low-risk conditions, they maintain traditional reclosing cycles to preserve service continuity. This dual capability allows utilities to balance fire mitigation with reliability, adapting operational modes to real-time environmental and system contexts.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: The principal benefit of adaptive reclosers is their ability to prevent repeated fault energization, a major ignition risk under wildfire-prone conditions. Traditional protection devices automatically attempt to reclose a line after a trip, often multiple times, in the hope that the fault is temporary (e.g., tree branch contact). However, in high-fire-risk periods, each reclosing attempt increases the likelihood of sparks, molten metal, or sustained arcing that could ignite nearby vegetation. Adaptive reclosers modify reclosing sequences during such periods, thereby directly mitigating this hazard. Importantly, they do so without fully compromising reliability, since reclosing remains enabled under safe conditions, thereby maintaining service continuity. In contrast to conventional devices that operate without contextual awareness, adaptive reclosers provide condition-dependent protection. This reduces both the probability and severity of fire events while preserving system resilience, aligning grid operations more closely with evolving environmental risk profiles.

Challenges of Implementation: Despite their promise, adaptive reclosers present significant implementation challenges. A critical requirement is the availability of accurate, real-time fire-risk assessments derived from weather forecasts, vegetation data, and local fuel conditions. Without reliable data inputs, recloser operations can be overly conservative (leading to unnecessary service interruptions) or insufficiently responsive (thereby failing to prevent ignition events). Integration with existing utility protection schemes can also be complex, as coordination must occur across relays, sectionalizers, and other protection devices to avoid unintended protection gaps. Furthermore, utilities must carefully balance customer expectations for reliability with risk-reduction objectives, particularly in rural or radial networks, where reclosing is essential to maintaining service to loads at the far ends of the network without access to redundant electricity delivery paths. Finally, implementing adaptive schemes requires advanced communication infrastructure, analytics platforms, and operator training, all of which contribute to higher capital and operational costs that must be justified against potential risk reductions.

Examples: Avista's dry-land mode applies fast-trip settings with reclosing disabled on high-risk circuits during fire season to quickly de-energize lines and reduce wildfire ignition risk.

Future Direction: Looking ahead, adaptive reclosers are likely to evolve into more autonomous, data-driven systems. One future direction involves leveraging AI algorithms and sensor fusion to continuously analyze real-time weather, vegetation, and grid operating data, enabling dynamic adjustments to reclosing thresholds without operator intervention. Another promising avenue is their integration with distributed energy resources and microgrids. For instance, when reclosing is disabled on a main feeder because of fire risk, sectionalized zones supported by distributed energy resources could continue to operate independently (at least partly), maintaining local supply and resilience. Such advances will transform adaptive reclosers from purely protective devices into active enablers of risk-informed, resilient grid operations.

4.3.3 Advanced Fire-Safe Devices for Monitoring and Controls

Description of Practice: Advanced fire-safe devices encompass a class of intelligent monitoring and control technologies specifically designed to operate safely in wildfire-prone regions. These include line-mounted fault indicators, conductor-mounted sensors, and automated switches that detect abnormal conditions such as overheating, arcing, or conductor sag. Unlike traditional expulsion-type fuses or surge arresters, which may themselves generate hot particles or sparks when interrupting faults, fire-safe devices are engineered to minimize ignition risks while maintaining protective functionality. Their deployment enables utilities to replace high-risk legacy equipment with modern alternatives that integrate seamlessly with advanced protection schemes and supervisory control systems, thereby enhancing wildfire resilience. As weather or other environmental conditions exceed utility-defined thresholds, these systems, when used in peri-event conditions, become critical for quickly monitoring system issues.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: The central benefit of advanced fire-safe monitoring and control devices is their ability to detect faults rapidly and precisely, enabling utilities to de-energize lines before they escalate into ignition events. By replacing traditional devices that rely on mechanical expulsion or delayed tripping, these technologies significantly reduce the release of sparks, molten particles, or arcs during fault clearing. Intelligent sensors further enhance situational awareness by delivering real-time monitoring of conductor temperature, mechanical strain, and vibrations. These factors are closely linked to the potential for wildfire ignition. When paired with automated switching, utilities can sectionalize and isolate high-risk segments more effectively, ensuring that the broader system remains operational.

Challenges of Implementation: Despite their promise, the widespread deployment of advanced fire-safe devices faces notable challenges. High installation costs, particularly in remote or rugged terrain, present a barrier for many utilities with large service territories. Integration with existing protection and communications infrastructure requires careful planning, as legacy systems may not support the volume or type of data produced by modern sensors.

Furthermore, continuous monitoring generates vast amounts of data, which, without effective analytics and filtering, can overwhelm operators and dilute actionable insights. Ensuring cybersecurity and communications reliability in remote, fire-prone areas also poses technical difficulties.

Examples: Commercially available non-contact (i.e., mounted adjacent to conductors) conductor monitors are sensors that provide real-time monitoring of conductor health and detect anomalies that could lead to wildfire threats. They support situational awareness and wildfire risk reduction efforts by using a combination of optical and electromagnetic field sensors in conjunction with weather stations to detect and notify upon anomaly detection. Bear Valley Electric Service installed line-mounted fault indicators, and Consumers Power replaced field hydraulic reclosers with dielectric reclosers with relay controls. Glendale Water & Power is conducting engineering studies to determine the efficacy of installing advanced sensors at substations in high-fire-risk districts.

Future Direction: The future of fire-safe devices lies in the integration of edge AI and distributed analytics for predictive fault prevention. By fusing real-time weather data, vegetation growth patterns, and asset condition information, these devices can autonomously assess ignition risks and trigger preemptive responses. These can include actions such as localized de-energization or dynamic protection setting adjustments. Autonomous control will reduce dependence on operator intervention, thereby improving response times during critical fire windows. Over time, these systems could also be integrated with distributed energy resources and microgrids, ensuring local supply continuity even when circuits are isolated.

4.4 Enhanced Powerline Safety Settings (EPSS) Controls and Public Safety Power Shutoff (PSPS) Activation

Description of Practice: When wildfire risk reaches critical levels, utilities can use tiered EPSS controls and/or implement a PSPS action based on predetermined environmental triggers. Under EPSS, devices configured with higher sensitivity or non-reclose settings detect and trip on electrical faults in real time, cutting power instantly to affected sections to mitigate utility-caused ignition. A PSPS involves deliberately de-energizing defined line segments in high-risk areas. Activation can require early notification to affected stakeholders, including customers and emergency personnel. Both EPSS and PSPS are temporary measures—following a period of elevated risk and line inspection, power is restored. PSPS activation can affect both distribution and transmission networks, depending on the lines de-energized. EPSS controls are primarily applied to distribution systems because these have a higher concentration of vegetation and therefore a higher ignition potential. However, utilities can also apply EPSS to transmission circuits in high-fire-risk districts. For energized lines that may run parallel to a de-energized line under EPSS or PSPS conditions, special consideration should be given to the potential for static charge buildup, which has been shown to ignite fires or pose a safety concern for individuals working in the area.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Both EPSS controls and PSPS activation enable swift, targeted response during periods of elevated risk, and settings are flexible to changes in risk. EPSS is more nuanced in its ability to adjust operations across tiers according to risk conditions. At an elevated EPSS tier, once a line fault is detected, it triggers a line shutdown, which is virtually automatic and isolated to the affected segment to minimize ignition risk and the scope of the outage. Although PSPS is often considered a last resort because it involves de-energizing a large portion of the grid, it has the benefit of fully eliminating utility-caused ignition risk, and customers may receive advanced notice.

Challenges of Implementation: A challenge in activating EPSS or PSPS is balancing wildfire prevention with unnecessary outages. Outages associated with EPSS and PSPS can affect emergency communications, medical facilities, and the water supply for firefighting purposes. An additional challenge is that some utilities lack remote operating capabilities to adjust recloser settings, requiring manual changes at substations.

Examples: Once an EPSS or PSPS horizon is established, utilities (such as Anza Electric Cooperative and Bonneville Power Administration) contact government agencies, first responders, and the community at least 2 days prior to activation. There are cases, however, where conditions can materialize more quickly than within two days, and in such cases, notification is provided as soon as possible. Utilities that have a supplier (e.g., Salem Electric via Bonneville Power Administration and Rancho Cucamonga Municipal Utility via SCE) do not necessarily implement a PSPS plan; instead, they coordinate with their provider. In addition to manual activation, PSPS or EPSS can be activated remotely. For example, Kootenai Electric Cooperative uses a SCADA system to control feeder relays at substations. As exemplified by Central Electric Cooperative, the decision to activate can be triggered by personnel assessments of local conditions, national alerts such as RFWs, or the attainment of critical thresholds for humidity, temperature, or wind speed.

Future Direction: Detailed action plans outline EPSS and PSPS protocols to create a streamlined process with effective communication during activation events. Puget Sound Energy utilizes the Federal Emergency Management Agency NIMS for emergency response, adapts the U.S. National Park Service ICS into the response process, and coordinates training and exercises off-season (FEMA, 2017)). Because EPSS and PSPS critical event horizons are on the order of hours to days, utilities should adopt similar practices for real-time operations, including the adoption of enhanced situational awareness (Section 4.1). For grid resilience during PSPS or EPSS activation, utilities can consider designing and implementing sectionalizing, islanding, and microgrid systems to minimize outage areas and maintain critical loads for essential services, as done by Lassen Municipal Utility District and Kirkwood Meadows PUD. Another technique to facilitate activation is remote access for automation and rapid decision-making during an active wildfire.

4.5 Customer Engagement and Resourcing

Description of Practice: Customer engagement during a wildfire event involves multichannel communication to disseminate key developments in a timely manner. Communication can include wireless emergency alerts, newsletters, press releases, social media notifications, daily workshops, and interactive risk zone maps. During EPSS or PSPS activation horizons, there is preliminary engagement up to 48 hours prior to an event as well as continuous updates. During an active wildfire, advanced notification may not be possible. Many utilities also open resource centers for customers to get out of the heat or the cold or to charge devices.

System Application: Transmission systems, but it is also applicable to distribution through general utility preparedness.

Risk Mitigation Benefits: Transparent communication with customers about mitigation efforts and safety measures reduces wildfire risks, increases customer preparedness, and builds trust with the community. Outreach enables real-time awareness, keeping affected residents informed about the latest developments and potential outages during wildfire events.

Challenges of Implementation: To the best of their ability, effective communication during large-scale events must be frequent and consistent across multiple broadcast platforms (e.g., social media, websites, radio, television, physical signboards) during a wildfire to minimize misinformation and ensure safety as conditions change. Effective engagement involves strategies tailored to diverse demographics as rural populations may have less access to certain communication resources than urban populations, particularly if internet or cellular coverage is limited. Striking a balance between an adequate number of notifications and overcommunication can prove challenging because of the propensity of weather or wildfire conditions to change rapidly. There are cases where rapidly developing risk conditions only allow for short notice to customers, and thus the need for distributed communications planning across a variety of situations.

Examples: The information that a utility provides to customers includes the outage's cause, extent, repair status, and restoration window. In addition to common communication channels such as phone, email, and web posts, Liberty Utilities also designed roadside changeable message signs to use through affected communities. To reach rural customers and connect with emergency response teams, Rocky Mountain Power uses a deployable cell tower that generates coverage. Utilities generally tailor communication to individual populations that may have limited access to information or limited English proficiency (Bear Valley Electric Service). Clark Public Utilities developed a crisis communication plan to streamline response, including an online outage center to focus communication. For resourcing, Rocky Mountain Power developed an emergency coordination center to deploy crews and coordinate with local and regional agencies, and Portland General Electric Company established community resource centers to support affected communities by providing relevant supplies.

Future Direction: Broadening the range of notification channels used—such as automated calls, emails, social media alerts, news partnerships, and hotlines—will improve communication. Utilities can increase accessibility by developing strategies that specifically target vulnerable populations and multilingual households. Surveying customers following an event will enhance the effectiveness and transparency of communication during subsequent wildfire events. Additionally, utilities can partner with local agencies to integrate utility alerts to broaden outreach to customers and stakeholders.

4.6 De-energization as a Mitigation Practice

Description of Practice: When an active wildfire is in progress, de-energization is a mitigation strategy that temporarily shuts off power to specific lines to prevent electrical infrastructure from contributing to secondary ignition or the spread of wildfire. De-energization can be manual or automated and is triggered by direct threats to infrastructure, requests from emergency agencies, and observed hazards. To mitigate the impacts of de-energization for customers, including businesses and those utilizing medical support devices, utilities ensure timely communication and offer direct community support through mobile emergency generators and support centers. To reduce outages caused by de-energization, utilities utilize alternative energy sources, microgrids, islanding, and load transfer (NERC, 2021).

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: By de-energizing lines at risk of being damaged, utilities prevent secondary ignition from events such as faults and arcing or flashover through smoke. De-energization also protects first responders, crews, and emergency personnel from electrical hazards during firefighting activities. Targeted de-energization ensures immediate risk reduction while only affecting the portion of the line that is threatened by wildfire, thereby reducing the occurrence of outages.

Challenges of Implementation: De-energization of circuits is unplanned and not proactive like PSPS, so advanced notification to customers and stakeholders is not always possible, leading to negative effects on homes and businesses. De-energization can also disrupt critical services such as firefighting and coordination efforts because power may be required for water system operations, cell towers, traffic signals, and communication sites. Another challenge is manual switching, which delays de-energization and poses a greater risk during a wildfire, particularly in remote and hard-to-access areas that could become blocked due to fire or weather than can down trees across access roads. In the event of outages related to de-energization, mitigation strategies like securing alternative energy sources or establishing mobile support centers require additional costs and considerations.

Examples: Utilities reactively de-energize lines during a wildfire. Rocky Mountain Power Utah takes this approach to mitigate wildfire spread risk from electrical equipment, and Seattle City Light does this to ensure safety during firefighting activities, such as helicopters releasing water on wildfires near power lines. In the event that overhead transmission lines are de-energized, Kirkwood Meadows PUD employs an emergency generation facility to restore power to distribution systems and customers. Many utilities (e.g., Central Lincoln PUD and Oregon Trail Electric Cooperative) de-energize lines remotely through SCADA-enabled devices. However, some line sections are not remotely controlled and thus require manual action. Moreno Valley Utility does not de-energize during wildfire events because all of its distribution lines are underground.

Future Direction: Utilities can implement automated reclosers and SCADA systems to reduce the risk to crews and the prolonged exposure involved in manual de-energization. Those with existing capabilities can leverage installed infrastructure to shrink the outage footprint by targeting and sectionalizing lines that are most at risk during a wildfire event. Leveraging other infrastructure for de-energization efforts would be beneficial. For example, visual surveillance systems enable smoke identification, shortening the response time for de-energization and strengthening mitigation efforts. Utilities should also consider adopting frameworks such as the NIMS and ICS to improve coordination and communication during de-energization events, as reactive de-energization events are often triggered by requests from emergency personnel, local police, or fire officials.

5.0 Resilience as Rebound (Post-event Recovery) and Sustained Adaptability (Long-Term Improvement)

Following an event, utilities shift to recovery or rebound stages. In the short term, best practices in this phase aim to assess damage and restore utility services to customers, on a scale of hours to days. However, it is important to recover to a state that is potentially more stable or resilient than the pre-event state. This requires sustained effort in adaptability over months to years. Furthermore, many electric utilities are adopting a continuous learning, adaptation, and improvement cycle to enhance their wildfire mitigation strategies, recognizing that a static plan is insufficient in the face of dynamic conditions and escalating risks. In this approach, the utility refines its readiness by creating a feedback loop that integrates data, operational feedback, and new technologies, many of which are discussed in this section. The practice of continuous learning is a core component of the post-event phase of wildfire mitigation, involving a systematic, data-driven process of analyzing past events and making strategic adjustments to prepare for the future.

5.1 System Inspection and Restoration

Description of Practice: System inspections identify outage causes, assess the condition of electrical infrastructure, and investigate the surrounding environment to ensure a safe and efficient return to service in affected areas. Inspections involve ground patrols and aerial technology, such as UASs, to assess poles, conductors, insulators, and vegetation for damage. Power can be fully restored following grid inspection or restored incrementally as lines pass inspection. During EPSS outages, inspections identify the cause of faults that triggered de-energization. For outages associated with PSPS, lines are re-energized once fire-weather conditions subside below specified risk thresholds. This best practice can be paired with other opportunities, such as mutual aid agreements, in which utilities with shared ROWs will enter into agreements to share post-de-energization patrol/inspection duties, thereby decreasing the overall outage duration for both utilities.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Post-event inspections ensure reignition risk is low by identifying and addressing smoldering hotspots, “zombie fires” (reignition of fire after dormancy), changes in vegetation, or damaged infrastructure that could spark when power is restored. Damaged facilities or vegetation issues are documented and photographed, and EPSS or PSPS event actions can be reported to gather insights for future post-event recovery efforts. If restoration requires rebuilding, system hardening measures can be implemented to increase resilience.

Challenges of Implementation: Ensuring service inspection and restoration are both safe and rapid requires structured protocols and effective coordination to mobilize patrols, perform cleanup, and communicate with stakeholders. Inspection and restoration may be delayed if weather conditions shift or are forecast to become hazardous again. Restoration is also delayed if inspections reveal new hazards that warrant an elongated outage duration while debris is cleared or infrastructure is repaired. Another challenge is inspecting large swaths of the grid in remote or burned areas. Even with the use of visual technologies like aerial surveillance systems, views can be obstructed by smoke without the right sensors.

Examples: Utilities like Arizona Public Service and Consumers Power employ line crews to inspect infrastructure for potential hazards such as downed conductors prior to re-energization.

Advanced technologies can also aid in patrol. For example, Idaho Power Company and San Francisco Public Utilities Commission use helicopters, and SDG&E and Inland Power & Light Company use UAS. Following visual inspection of event-involved assets, Lodi Electric Utility follows an electric emergency plan that prioritizes vital loads by designating the order of circuit restoration. Garkane Energy Cooperative also employs step restoration to re-energize circuits in segments as patrols continue. Some utilities patrol power lines a second time following restoration to ensure there are no remaining issues that can cause outages (e.g., United Power).

Future Direction: In addition to purchasing equipment like autonomous UAS to aid in inspection and restoration, utilities can retain contractors, adopt mobile software, and record data. For events that affect a large portion of the grid, utilities can leverage mutual aid agencies and contractors to supplement inspection crews when staffing is insufficient, as Redding Electric Utility and Bear Valley Electric Service have done. To strengthen communication during inspections and restoration, Bear Valley Electric Service adopted the iRestore App, which enables the utility to coordinate with first responders through direct mobile device reports. Other utilities can consider integrating iRestore into their management practices. To strengthen preparedness for subsequent wildfires, recording performance metrics and outage characteristics during the post-event recovery process provides insight into grid vulnerabilities. California utilities such as PG&E are required to report fire-related outages to California Public Utilities Commission, providing information such as EPSS and PSPS event frequency, scope, and duration.

5.2 Post-fire Vegetation Management

Description of Practice: While most vegetation management activities conducted by utilities focus on preventing vegetation-related outages and wildfires (summarized in Section 3.8), there are still certain risks associated with post-fire vegetation that utilities must mitigate. The process begins with emergency management agencies inspecting and documenting impacts in wildfire-affected areas as soon as it is deemed safe to do so. Federal land management agencies such as USFS and BLM developed programs like Rapid Assessment of Vegetation Condition after Wildfire, which provides assessments of fire-affected vegetation. Next, utilities remove hazardous trees or vegetation that pose fall-in or safety risks, inhibit the ability to re-energize, or block access for emergency response personnel. Detailed investigation of what caused the fire or outage is then completed by utility vegetation management professionals to support objective, data-driven program changes throughout the season. Longer-term management activities may include vegetation restoration with the aim of reducing future grow-in risk by planting low-growing species, reducing fuel loads by planting fire-resistant vegetation, stabilizing adjacent hillslopes that pose severe erosion or landslide risks, and addressing conservation goals. Federal programs such as Burned Area Rehabilitation may guide or support restoration efforts on federal lands. As such, post-fire vegetation restoration is not mutually exclusive to pre-fire conservation and fuel reduction practices.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: The primary benefits of removing hazardous vegetation after a fire are reducing safety risks to the public, utility personnel, and emergency management crews, and restoring power as soon as possible. Benefits of post-fire vegetation restoration include reducing the future risk of vegetation-related ignitions or outages, landslides, soil erosion, and addressing conservation goals.

Challenges of Implementation: Inspecting wildfire-affected areas in a timely and safe manner is perhaps the most significant challenge because of ongoing safety concerns during an active fire event. This requires close coordination with fire managers and crews, which can be challenging given their primary focus on fighting the fire. Inspections are typically conducted by ground crews, which can take considerable time, depending on the size of the wildfire-affected area, the extent of access restrictions, and the remoteness of the infrastructure. Post-fire vegetation restoration activities may require additional coordination and approval from local land managers (federal, state, county, and private).

Examples: Post-fire vegetation management, particularly the removal of hazardous fire-affected trees, is a common practice among both small and large utilities. Some examples of utilities that include this strategy in the WMPs are the Benton Rural Electric Association and Mascon County PUD No. 1 in Washington (Benton Rural Electric Association, 2024); PacifiCorp, SDG&E, Healdsburg Electric Department, PG&E, and Horizon West Transmission in California; Idaho Power Company in Idaho; and Hawaiian Electric Company in Hawaii.

Future Direction: The use of remote sensing technologies, such as UAS and satellite imagery, to aid post-fire damage assessment and vegetation monitoring is likely to increase as these technologies become more affordable and accessible to utilities. Some utilities also recognize that wildfires present an opportunity to undertake vegetation management actions that are more likely to succeed following a major disturbance (e.g., planting species that are more fire-resistant and that reduce fuel loads, improve biodiversity, create pollinator corridors, and prevent undesirable or invasive species).

5.3 Emergency Preparedness Plans

Description of Practice: Emergency preparedness plans are comprehensive strategies for disaster preparedness, response, and safe, efficient recovery from outages, including those caused by wildfires. These plans proactively mitigate threats by outlining a range of policies, programs, processes, and procedures. They focus on establishing safety as the top priority and detail methods to enhance situational awareness, notification, preventive measures, and specific response and recovery actions related to wildfire risks. Generally, these plans include communication plans, protocols, and procedures for de-energizing power lines and restoring service. The plans should be integrated across multiple actors, including operators, asset managers, communities, first responders, and local governments.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Emergency preparedness plans have a primary goal of protecting public safety and safeguarding human lives, physical assets, and property. These plans provide guidance to enhance effective response and recovery efforts through communication and explicit procedures.

Challenges of Implementation: Each utility faces unique challenges based on its specific geography, terrain, vegetation, and other characteristics. This necessitates tailored approaches rather than a one-size-fits-all solution. There are challenges in coordinating with community actors and first responders, as well as in creating these plans for implementation. Additionally, training and education requirements should be implemented to ensure that all personnel and actors understand their duties and responsibilities under the emergency preparedness plan.

Examples: Bear Valley Electric Service uses emergency preparedness plans that outline customer support and communications protocols. Its Emergency Preparedness and Response Plan comprises an emergency protocol and a communications plan, and prioritizes partnerships with local agencies, such as the USFS, for fire prevention and suppression. SCE bases its emergency preparedness and response plans on “enhancing operational practices” (such as PSPS protocols) and “providing services during a de-energization event” as key pillars to minimize public safety risks.

Future Direction: The development and use of emergency preparedness plans should include an annual review and necessary adaptations to address changing conditions in the built and natural environments. The plans should also be reviewed to ensure they are fully integrated and facilitate seamless coordination among relevant stakeholders. This means the plans should focus on strengthening the communication, policies, and procedures among the relevant utility personnel and external partners (i.e., first responders, local government, other utilities, or key facility operators, communities). A plan's effectiveness hinges on multi-actor integration to ensure a safe, efficient, and coordinated response and recovery, especially when addressing the complex and interconnected risks posed by wildfires, which further emphasizes that table-top and other training exercises (Section 3.12) are necessary to test the plan's value and address gaps and challenges.

5.4 After-Action Reporting

Description of Practice: After-action reports (AARs) are structured reviews or debriefing procedures conducted at the conclusion of emergency events, such as wildfires or PSPS events. These reviews typically involve soliciting feedback from all relevant participants, including staff, customer service providers, local government agencies, and partner organizations. The insights gathered from these discussions are compiled into a formal document, often referred to as an after-action report and improvement plan (AAR/IP). The core purpose is to identify which procedures and actions were effective and which were not, and to discuss solutions or plan future meetings to address the identified problems.

Logs are typically maintained during major incidents to aid in reconstructing events for these reviews. Debriefings can range from informal, high-level discussions to formal hot washes.

The content of an AAR can be comprehensive, often including the following elements:

- Date and time of the incident
- Description of the incident
- Level of plan activation and whether the emergency operations center was staffed
- Records of public communications that were performed
- List of damages to the system
- List of personal deaths, injuries, and other accidents associated with the incident
- List of external resources utilized (contracted and mutual aid)
- Incremental cost of emergency response actions
- Lessons learned (i.e., insights gained from the experience)
- Evaluation of whether the plan was properly followed

- Specific improvement actions, including assignment of responsibility and due dates

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: The primary benefit of after-action reporting is the creation of a learning feedback loop. This transforms a past event from a one-off incident into a valuable data point for future risk reduction, facilitating continuous improvement in wildfire mitigation strategies, emergency response, and restoration processes. Specifically, AARs allow refinements to operational protocols, enabling identified weaknesses in response and recovery to be addressed and successes to be recognized and championed. Furthermore, AARs can help identify which investments (e.g., specific grid-hardening projects, new monitoring technologies, training, or resource-strategizing efforts) yield the greatest return on investment, guiding future capital allocation. Documenting (via AARs and follow-on reporting), performing analysis, and planning are part of a continuous improvement process that can help meet regulatory requirements, facilitate insurance evaluations, and serve as a key component of a utility's defense against liability claims by demonstrating that it has a reasonable, evolving plan to address wildfire risk.

Challenges of Implementation: Data capture methods are not always standardized, making it difficult to accurately compare past performance with current and future trends. A lack of standards will be further exacerbated by the volume and variety of data that are generated during and after a wildfire event. Furthermore, a lack of integration among systems across utility departments can further degrade the effectiveness and timeliness of AARs in gathering the required data. While larger, more resourceful utilities have sufficient staff to dedicate to AARs, smaller utilities may be limited in their ability to perform this function effectively. In considering the usefulness of AARs, it is essential to create a learning culture in which openness and transparency within utility processes allow for the recognition and acceptance of failures and mistakes, with the intent of building and improving in the future. Rules may be considered regarding liability protections and/or data-access controls to remove significant barriers to data sharing. The objective is to improve understanding of the environmental and system factors that led up to an event, so learning and actions can be taken in the future.

Examples: Many utilities explicitly incorporate after-action reporting and lessons learned into their processes. Arizona Public Service (APS) conducts debriefings at the conclusion of emergency events and compiles notes into an AAR/IP to make changes to processes, systems, plans, or procedures. Clark Public Utilities assesses its company-wide wildfire mitigation efforts at the end of each fire season, tracking fire starts and integrating lessons learned and new best practices into its next WMP iteration. PUD No. 1 of Douglas County prepares incident reports after wildfires to evaluate the effectiveness of its WMP and identify areas for improvement, leading to updates and new tactics and procedures.

Future Directions: It is anticipated that the future of AARs will be driven by technological advancements and a shift toward more automated, proactive, and real-time analysis. AI/ML will increasingly be used to automate data gathering and analysis, generating preliminary reports and flagging key issues. The development of digital twins will enable utilities to replay past events in a simulated environment, allowing for a more detailed analysis of "what if" scenarios if different actions had been taken. This allows for a deeper understanding of the actions and consequences of physical improvements, technology investments, and system operations. Underpinning all of the above are the planning, investment, and use of collaborative platforms that provide multi-departmental data, reporting, and analysis. Furthermore, as a benefit to the community as a whole, utilities may begin contributing to and using shared, anonymized data platforms to compare their AAR findings, thereby enabling the industry to learn more quickly from a wider range of events and to accelerate the development of best practices.

5.5 Tracking Performance Metrics

Description of Practice: Tracking performance metrics involves measuring and analyzing data to evaluate the effectiveness of response and recovery efforts following a wildfire event. This process enables utilities to evaluate restoration speed, assess program effectiveness, enhance safety measures, and inform future mitigation strategies. Performance metrics include EPSS and PSPS frequency, the number of circuits de-energized, the number of affected customers, and the customer notification success rate. Metrics can also include reliability indices such as the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI), which assess service reliability based on the average number of outages and their average duration, respectively, and inform utilities about the effectiveness of system hardening. Other commonly used reliability metrics include the Customer Average Interruption Duration Index and the Momentary Average Interruption Event Frequency Index. These indices are defined by the Institute of Electrical and Electronics and Engineers (IEEE) Standard 1366 (IEEE, 2022). Performance data to calculate metrics are collected from outage management systems, vegetation management records, and situational awareness technologies such as weather stations, drones, and cameras.

System Application: Applicable to transmission systems as well as distribution systems.

Risk Mitigation Benefits: Performance metrics provide a data-driven evaluation of programs, enabling the identification of areas for improvement and quantification of customer impacts. By tracking metrics, utilities can identify high-risk areas for further monitoring, reduce the likelihood of utility-caused ignitions, target infrastructure that requires improvement to enhance resilience, and adjust inspection schedules to ensure preparedness. Results can also be benchmarked against state and national averages to enable comparisons among utilities based on performance metrics such as outage frequency and duration. Overall, tracking performance metrics enables continual improvement to mitigate the risks that wildfires pose to public safety and infrastructure.

Challenges of Implementation: As utilities begin to implement performance metrics, limited data will be available for early years. This poses challenges for conducting trend analysis to determine the effectiveness of mitigation efforts, such as system hardening. Additionally, capturing and compiling these data often requires a manual effort or resources to implement new tools and technologies. Metrics like “wires down” may be influenced by extreme events unrelated to wildfire, which must be accounted for in performance assessments. For underground systems, traditional metrics may be inapplicable and require adaptation, such as using routine inspections on aboveground substations as the primary metric to mitigate utility-caused ignitions.

Examples: Many utilities use multiple metrics to track the performance of WMPs. For example, SCE implements 58 activity and metric goals as program targets to inform compliance. The Transmission Agency of Northern California tracks ignitions, wires down, equipment failures, vegetation-caused outages, hazard trees removed, and acres of fuels treated to evaluate WMP effectiveness. By contrast, some utilities track very few or no metrics. Kittitas County PUD No. 1 is developing performance metrics, whereas Victorville Municipal Utility Services only tracks utility-caused fire ignitions. The City of Corona Utilities Department tracks ignitions and outage events, but the utility has not had any fire ignitions since the plan was implemented. To process metrics related to utility-caused ignitions, Hawaiian Electric Company collects ignition data through its Ignition Management Program, which informs future mitigation efforts, such as risk modeling. Hawaiian Electric tracks a series of performance and progress-based metrics to evaluate the change in its systems and risk over time.

Future Direction: Utilities that do not currently track performance metrics or plan to implement metrics should consider including them in the future, particularly standardized metrics commonly used among utilities, such as reliability indices (IEEE, 2022). For utilities that do track performance metrics, if resources allow, adding more metrics, such as outage data in addition to vegetation cleared, enables a comprehensive evaluation of the system, which leads to greater risk mitigation. Metrics should be modified or added as risk evolves, data become available, and technology improves.

6.0 Regulatory Frameworks and Policy

6.1 Regulatory Landscape

There are over 3,000 utilities providing electricity service in the United States.[1] Utilities may be public—meaning that they are operated by a municipal government or special district with publicly elected oversight—or they may be private, owned by investors or by their members through a cooperative. Utilities are commonly separated into two categories: 1) “consumer-owned utilities,” which include municipalities, PUDs, rural electric cooperatives, and 2) “investor-owned utilities,” which are subject to special regulatory oversight to ensure fair electricity rates and quality of service. There are many additional contributors to electric service, such as independent power producers and federal power marketing administrations. The dominant regulator for an investor-owned utility’s provision of service, from customer satisfaction to investment strategy oversight, is the state government. For this reason, state regulatory utility commissions are the primary regulators of utility wildfire mitigation.

For most utilities, wildfire management has historically been concentrated under vegetation management programs. Vegetation management programs are not financially significant to the rate base. Utility programs employ licensed arborists (such as those within the Utility Arborist Association) for urban, suburban, and rural vegetation management. They follow standard corporate land management protocols for assuring that utility corridors are deconflicted with other uses. Best practices, such as IVM, periodic surveys, and other advanced corridor awareness practices, are indicated in earlier sections.

For state utility regulatory commissions with expertise in engineering, law, and economics, wildfire mitigation is new territory. It is common practice to offer great deference to utilities in vegetation, corridor, and distribution utility asset management protocols and costs. The significance of utility wildfire mitigation planning—whether driven by public inquiry, legislative direction, or total customer costs—has now prompted regulators and utility oversight bodies to establish a new practice.

6.2 Utility Planning Paradigm

With the advent of wildfire as an acute electricity issue, utility regulatory commissions began to scrutinize vegetation management practices and a range of other standard utility programs that evolved in response to new wildfire de-risking responsibilities. Utilities already have emergency operations plans, and many have plans organized around forward risks and multiple hazards, such as resilience plans. For example, Nevada Energy developed a Natural Disaster Protection Plan that covers wildfires, storms, and other events.

The emergence of utility WMPs is rooted in California practice. California and Nevada introduced the first legislation requiring WMPs or wildfire protection plans in 2019. Since then, seven states have enacted legislation requiring WMPs. Three states require them as a component of qualifying for reduced risk, reduced damages, or utilization of a public fund for damages, and three additional states passed legislation to require or encourage them in their 2025 sessions.

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[1] Natural gas utilities may also develop wildfire mitigation plans, but they are not the target of legislative requirements and do not have the same risk of igniting a wildfire.

An expanding number of states now require utilities to produce WMPs. The legislation typically indicates the contents and schedule for the plans. Initially, WMPs were issued annually. Recently, many large utilities have moved to three-year planning periods to reflect the duration of their intended investment. For example, undergrounding lines is expensive, requires strategic selection, and takes a long time to complete. Other utilities issue only brief annual updates to their previous, more robust mitigation plans.

As with most utility plans submitted to oversight entities, such as integrated resource plans and WMPs, they are not strict commitments—they are analyses of possible scenarios and responsive utility actions. In addition to justifying later decision-making, these plans help explain the utility business to customers and gauge provisional regulatory responses for cost recovery. For this reason, utility plans are often acknowledged rather than approved.

Currently, several states have linked utility liability to a WMP approval process, representing a shift in oversight practice. Commission staff may lack the expertise or historical protocols to rely on for these important reviews, instead relying on multiagency partnerships or developing new protocols (National Association of Regulatory Utility Commissioners, 2025).

States have primary oversight and regulation of state-level investments and rates for regulated entities. As mentioned, state governments are the primary regulatory and legislative bodies overseeing distribution systems, customer rates, and service performance. Federal actors have noted shifts in oversight practices—for example, NERC's risk register does not specify wildfire but focuses more broadly on resilience to extreme events (NERC, 2022a, 2025b)—but have not had a significant direct role in managing utility responses to date.

There are emerging roles for federal energy actors:

- FERC oversees transmission planning, which can involve evaluating wildfire risk as part of anticipating future investments.
- NERC, via FERC, establishes and oversees compliance standards for reliability of the bulk-power system. Wildfires have caused significant disruptions to grid operations and are closely tracked by Western reliability entities (Western Electricity Coordinating Council [WECC], 2025).
- DOE research programs enable science, data, and analysis for wildfire risk assessment, forecasting, mitigation, response, and preparedness.
- DOE could facilitate independent reviews of utility and wildfire mitigation efforts, investments, cost-recovery, and liability considerations to provide accountability and insights for best practices.
- Providing guidance, tools, resources, models, data, and trainings that are equally accessible to all utilities.

Further, a review of the 2023 Wildland Fire Mitigation and Management Commission report and the pending bi-partisan Fix Our Forests Act (S. 1462) provides additional guidance and recommendations for where Federal entities may best interface with the energy sector and are further noted in Sections 3.8.4 and 3.13(Wildland Fire Mitigation and Management Commission, 2023; U.S. Senate, 2025).

6.3 Regulatory and Programmatic Practices in Play

Many practices in the regulatory space remain under development as the legal landscape is shifting. Issues germane to state energy offices and utility regulatory commissions include the following:

- *Public record of plans.* Currently, most states promote public distribution of WMPs. As a result, utility WMPs are publicly available, except for those of electric cooperatives.
- *Transparent reporting of implementation*. Costs and implementation activities, measurable progress, and success metrics are reported through the next iteration of WMPs or in cost recovery processes. Currently, the California Public Utilities Commission requires annual and responsive reporting of PSPS events. Oregon additionally requires confidential reporting to the Commission for jurisdictional utilities and non-confidential reports to be placed online on the utility website; the authors were able to verify partial performance of this requirement (Pacific Power, 2022, 2023).
- *Socialized/taxpayer costs or ratepayer costs.* As the private sector raises its costs (e.g., insurance premiums) and reduces its willingness to shoulder risk, that risk will be redistributed among companies, customers, and the public. There is no settled arrangement for how these costs should be managed, with significant differences between proposed and authorized wildfire mitigation costs that require negotiated settlements (Utah Public Service Commission, 2025; Colorado Public Utilities Commission, 2025). Through backstops and other strategies, stakeholders and governments are seeking new settlements to balance costs and risks across sectors.
- *Customer engagement*. Customers' awareness of wildfire—as well as their interests in balancing affordable rates with reliable service—requires a new level of direct engagement. Utility best practices in wildfire mitigation include:
  - Report on metrics via local and customer events, messages, and education.
  - Meet a new standard in terms of knowing the customer on the other side of the meter—whether providing a critical local service or an individual's reliance on electricity.
  - Directly invest in backup power or local power supplies to avoid impacts from service outages due to wildfire.
  - Implement notification protocols for customers affected by outages and adhere to notification timeframes.
- *Cost recovery mechanisms.* State commissions have authorized an array of actions to permit costs to be recovered, including in balancing accounts and trackers, in addition to traditional inclusion in rates (Utah Public Service Commission, 2025; Avista Utilities, 2022).

7.0 Cost Considerations

Costs for best management practices are nuanced and dependent upon the size, type, and complexity of the system. The intent of this section is to discuss opportunities for evaluating the costs of wildfires, co-benefits of best practices, and some cost-effectiveness evaluations at a high level. Utilities need to weigh the liability concerns, damage costs, and benefits associated with implementing best practices. There are unique considerations that need to be addressed on a utility-level basis that cannot be considered in these best practices. For example, some utilities might seek federal or state funding for assistance to implement these best practices, while other utilities will need to leverage existing capital improvement funds or identify costs against risk reduction to justify investment.

7.1 Reported Costs

Wildfire risk can lead to increased costs for utility customers in multiple ways:

- Utility spending on wildfire mitigation and risk coverage.
- Utility and customer contributions to state wildfire funds.
- Wildfire-related liabilities, including claims from property insurance companies seeking recovery from utilities through subrogation (Kousky et al., 2018).
- Downgraded credit ratings and increased utility cost of capital, which can ultimately translate to higher ratepayer costs.

Direct spending on wildfire mitigation currently is ~2-5 percent of utility capital spending, but the year-over-year spending for wildfire mitigation is growing (Barlow et al., 2025a). Additionally, as emphasized throughout this report, direct spending represents only a fraction of the wildfire-related costs utilities must bear, which may include payments for third-party damage, insurance costs, and other costs associated with capital cost increases and credit downgrades.

Capital spending (as opposed to operational spending) accounts for most wildfire mitigation spending for many utilities. Capital spending represents 55–86 percent of total wildfire mitigation spending across four utilities, where the split between capital and operational spending was reported. For investor-owned utilities, “prudently incurred” capital spending can become part of the regulated rate base, meaning costs are recovered from ratepayers and the utility earns a potential return on investment.

Increasing wildfire costs can put upward pressure on rates for all types of utilities, prompting trade-offs. Ratepayer recovery of wildfire costs directly affects customers, while limits on cost recovery and return on investment may compromise utilities’ ability to increase spending on wildfire mitigation and other objectives (S&P Global, 2024, 2025a, 2025b; Wara et al., 2024). In California, PG&E’s spending on wildfire mitigation is expected to increase at a compound annual growth rate of approximately 8 percent from 2020 to 2025, with spending in 2025 estimated to exceed $6 billion (PG&E, 2025b). The California Public Utilities Commission allowed customer recovery of $27 billion in utility wildfire-related costs from 2019-2023, representing ~7–13 percent of the average residential customer’s monthly electricity bill in 2023 (California Public Utilities Commission, 2024).

7.2 Co-benefits of Best Practices

From a cost perspective, the best practices for wildfire mitigation offer benefits well beyond wildfire mitigation alone. For example, hardening transmission lines can not only reduce wildfire risk but also increase robustness to high winds and reduce impacts from severe wind, rain, and ice storms. Similarly, vegetation management can both reduce the risk of wildfire impacts to utilities and improve reliability during additional disasters, from earthquakes to high-wind events to ice storms, and even blue-sky tree falls due to root rot and failing health. Therefore, the costs associated with best practices can be levelized across multiple natural disasters and threats, though they need to be factored into risk-spend efficiency (RSE), multi-attribute value function (MAVF), or other risk-quantification calculations and reliability metrics.

Additionally, best practices in asset management and asset health assessment (Section 3.2), which promote proactive investment and maintenance of equipment, have been shown to improve cost efficiency compared to reactive maintenance. Reliability-based asset management approaches can optimize costs and improve system performance for both wildfire and other events (Mirhosseini and Keynia, 2021). According to Modern Electric Water Company's WMP (2024), their best practices for wildfire mitigation help "reduce outages, damage, and other reliability-based…customer-experience issues."

7.3 Liability

Utilities are managing for two types of wildfire risk. One is traditional: the ability to withstand a hazard. The other, ignition risk from grid assets, is likely the area of focus for most utilities, as there is often a liability factor. The cost to a utility of both preventive mitigation of liability (insurance, loss of electric service, or infrastructure upgrades) and damages from utility-ignited wildfire can be enormous and pose an existential risk for utilities. Wildfire ignition caused the bankruptcy of one of the largest utilities in America, PG&E. Utility-caused ignition has decimated rural environments and iconic communities from the Texas panhandle to Lahaina, Maui, to Paradise and Los Angeles, California. Its shadow created the new-normal practice of PSPS. The electric utility business model is deeply affected: wildfire risk is a primary yardstick for utility credit ratings in 2025 (S&P Global, 2025a, 2025b). Costs and structures for insurance premiums alone have skyrocketed, with some utilities showing an insurance cost 35 times the pre-wildfire baseline (Barlow et al., 2025b). Ignition risk is of keen concern to public power utilities, who cannot afford wildfire-based liability, either in insurance premiums or in liability damages after an event (Brown, 2025; Serrame, 2025).

Policy-level action to reduce ignition risk is evident in a dramatic increase in state legislative activity over the last few years. States across the West have considered legislation, and many have passed laws that require utilities to develop and operate from WMPs. Four states —Utah, Oregon, Washington, and Hawaii —implemented WMP requirements between 2022 and 2024.

In some instances, the laws establishing WMP requirements also imbued those plans with protection against liability. As of 2025, Arizona, Idaho, Montana, Utah, and Wyoming have passed legislation that imposes a modified liability standard on utilities with a WMP approved by state regulators (Barlow et al., 2025a). Other states limit liability or damages by statute, without a direct connection to WMP requirements (Kincaid, 2026).

Two states (California and Utah) have "backstop" funds to support remuneration for wildfire damage claims. Four additional states proposed but ultimately did not approve the creation of payment funds or bond authorization. These decisions have an immediate impact on the market

(Wara et al., 2024). In September 2025, the California legislature voted to add more funds to its backstop, as the wildfire season in California is still ahead. Credit rating agencies responded publicly as favorable to the state investment but still maintained relatively negative to neutral positions on the three investor-owned utilities.

This topic is not yet in a state of resolution. Current best practices can be considered stopgaps designed to prevent the worst outcome, though their evolution and maturity are driving towards guiding principles that holistically enable a more robust, reliable, and safer system. States remain divergent on best practices, but as it is coming into focus, an individual set of best practices needs to be tailored to the place. This includes consideration of environmental conditions, the built and infrastructure environment, operational factors, risk factors, system interdependencies, social factors, and beyond, all of which drive towards the best guiding principles.

7.4 Cost-Effectiveness, Risk-Reduction Curves, and Metrics

A cited goal in many utility WMPs is to determine a reasonable balance between mitigation costs and the resulting reduction in wildfire risk. A commonly used metric for evaluating investments in wildfire mitigation best practices is RSE. Typically, this efficiency is calculated as the ratio of risk reduction to total cost of mitigation efforts, where a higher RSE indicates a greater benefit to the utility. Similarly, utilities will conduct cost-benefit analyses to quantify the impact of mitigation measures using monetized risk-avoidance. For example, PG&E has developed a Wildfire Benefit-Cost Analysis tool to evaluate its PSPS program against the potential losses from wildfire, accounting for undergrounding and other best management practices.

Utilities will utilize RSE and cost-benefit analysis to prioritize different mitigation approaches or best practices. Therefore, the most cost-effective or risk-efficient efforts are selected for implementation first. However, other factors and metrics can be leveraged for prioritizing alternatives, including qualitative risk scores and operational approaches (Hawaiian Electric Company, 2025). Another approach used for assessment is risk-reduction curves, which represent the relationship between risk reduction and cost for implementing different scenarios. Figure 6 shows an example multi-scenario risk-reduction curve, highlighting diminishing returns of risk reduction at certain levels of funding.

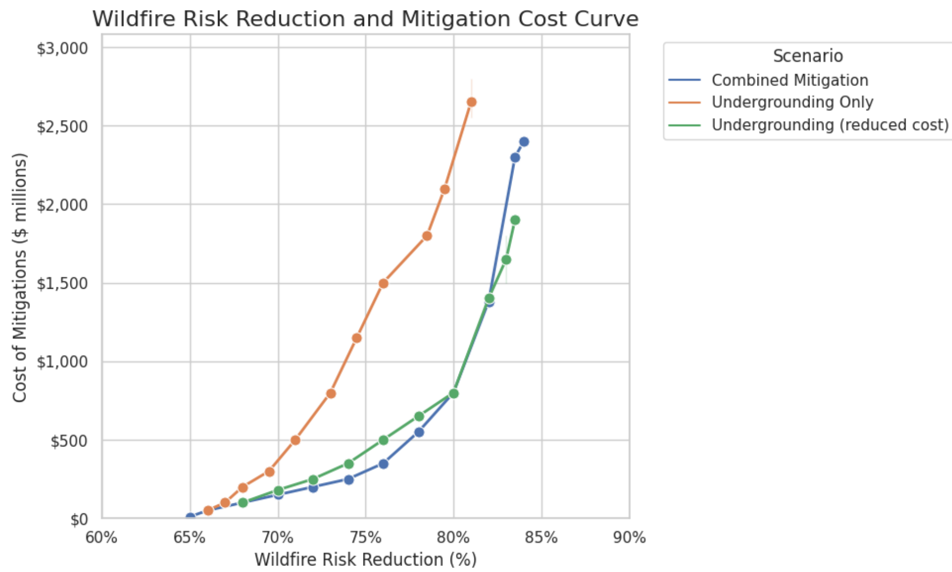

Figure 6. Example multi-scenario wildfire risk reduction cost curve (adapted from Hawaiian Electric Company's 2025-2027 Wildfire Safety Strategy [Hawaiian Electric Company, 2025]).

For risk quantification and prioritization, there are a few other methods documented in utility WMPs. SDG&E and other California utilities use a multi-attribute value function (MAVF) as their risk quantification frameworks, consistent with the California Public Utility Commission's requirements. The methodology estimates risk as a weighted sum across three categories: health and safety, reliability, and financial. Health and safety is weighted at 60 percent of the overall risk, reliability at 23 percent, and financial at 17 percent. Each of the sub-attributes has different values and ranges used to normalize against the likelihood of occurrence, see Figure 7. The resultant risk score can then be used to determine high-risk areas and prioritize location-specific interventions.

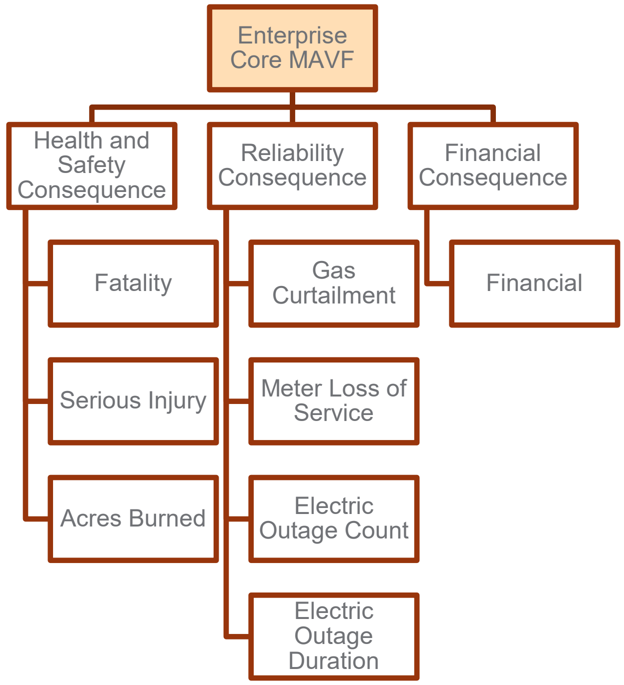

Figure 7. Risk indicators used for assigning risk-spend efficiency from San Diego Gas & Electric. MAVF = multi-attribute value function.

Similarly, APS calculates a fire-risk index using three equally weighted categories with 15 subcategories in 10 × 10 mile geographic grids. These values are then further categorized into three tiers to represent high-, medium-, and low-risk areas, with risk mitigation efforts prioritized. These categories and subcategories were identified through an expert-informed Delphi study.

Beyond the WMPs themselves, the academic literature offers insights into cost efficiency and related goals. The primary goals of cost-benefit analyses are often to avoid restoration and customer interruption costs (Collins et al., 2025). Damage cost estimation is a crucial aspect of resilience assessments, informing cost-benefit analyses and decision-making. However, there are opportunities to focus research on developing more accurate cost estimates for longer-lasting disruptions and associated widespread damage. In particular, estimates such as the value of lost load are often focused on short-term impacts, requiring additional research on long-term impacts (Baldursson et al., 2023). Additionally, there are challenges associated with how high-impact low-frequency events are measured due to difficulties in calculating the probability of occurrence (Afzal et al., 2020; Ratnam et al., 2020; Baldursson et al., 2023; Homer et al., 2025), necessitating further investments in models and methods for concurrence across the industry. Literature is sparse on cost-effective strategies for transmission system measures to reduce wildfire risk. However, this is an active field of research. Some strategies proposed in the existing literature are 1) an integrated model for financial risk assessment that can generate risk heatmaps to visually represent areas requiring immediate preemptive actions (Nematshahi et al., 2025), 2) a multi-period optimization formulation that not only sites and sizes different transmission infrastructure investments but also simultaneously chooses PSPS events to minimize ignition risk as well as load shedding (Kody et al., 2022), and 3) an operational resilience strategy summarized by a preventive-corrective scheme that utilizes contingency analysis tools to mitigate both static and dynamic insecurities, allowing for coordinated unit commitment and optimal power flow to reduce or mitigate ignition risk (Sahoo and Pal, 2025).

7.5 Collaborations for Cost-Effectiveness

One potential avenue for further development is to identify positive collaborations that could reduce overall costs, lowering impacts to consumers. Two key collaborative endeavors prioritize landscape-level planning.

- ***Beyond the Easement***: Power companies have agreements and easements with local landowners to allow for infrastructure and access to equipment. Often, this infrastructure is in remote or difficult-to-access areas (e.g., steep or remote terrain). The neighboring landowners, whether private, federal, or state owners, have a vested interest in reducing wildfire risk. Therefore, joint landscape-scale management can facilitate cost-sharing, reduce impacts on utility consumers, and support other fire-prevention and risk-mitigation efforts for various interests. Additionally, in many cases, access to power utility equipment is predicated on access roads, which may be easements or part of other agencies, such as the USFS. This infrastructure could serve a dual purpose, promoting accessibility to equipment for inspection/repair, while also acting as a natural fuel break if properly maintained to limit wildfire spread.
- ***Utility-to-Utility Efforts***: Service areas for utilities can often overlap and have fuzzy separations. As such, many of the best practices enunciated above can be leveraged across utilities to help share costs. For example, fire modeling or weather sensor data could be jointly funded for utilities in close proximity to one another with similar geographies to reduce the burden on consumers. Vegetation management in one utility's corridors could positively reduce fire risk to another utility as well. Essentially, coordination across utilities could reduce consumer costs by promoting efficiency and joint resource management.

Best practices do not have to be confined to the utility's service area. In fact, potential cost savings through sharing can be identified by coordinating with regional landowners and/or neighboring utilities. These relationships and collaborations should be identified by utilities to determine optimal strategies for reducing wildfire risk and cost burden on consumers.

8.0 Emerging Best Practices

Utility practices encompass potentially high-impact approaches to wildfire mitigation, including new research and development, gap identification, and the development of new solutions for the market. While these activities have not yet achieved sector-wide adoption as best practices, they are worth noting because they may be more broadly applicable in the future.

8.1 Wildfire Mitigation with Generation Assets

Utility wildfire mitigation planning typically focuses on transmission and distribution systems rather than on generation assets or substations. To date, generation in WMPs is mostly discussed in the context of mitigating reliability impacts, including emergency generation, temporary microgrids, and battery storage (Abernethy-Cannella et al., 2025).

Electric generating resources that rely on power lines in high-wildfire-risk areas also face challenges, although these may be less visible as they are "inside" utility operations and can be managed to avoid customer disruptions. For example, wildfire event data published by WECC indicated that in 2024, two major incidents involving the loss of multiple transmission lines resulted in the loss of approximately 1,000–2,000 MW of generation. In one case, about 1,000 MW of inverter-based resources were interrupted due to momentary cessation, while the second incident involved the designed tripping of roughly 2,000 MW through the proper operation of a Remedial Action Scheme (WECC, 2025). In 2023, Seattle City Light faced a similar problem when a primary transmission line became inoperable due to a nearby fire, resulting in the shutdown of a major hydroelectric facility. Customers were generally unaffected, but the utility was forced to manage facility emergency operations and sudden supply availability challenges (Seattle City Light, 2024). Hydroelectric plants with wildfire concerns may have their own wildfire mitigation activities, but these activities are overseen by a different division of the utility and reported to the primary regulator, such as under the FERC license.

Generation, transmission, and distribution are deeply linked in the process of providing electricity to customers. As wildfire mitigation planning matures, these enmeshed systems will also need to plan together. Entities with generating assets—especially remote assets—will cooperate more extensively with utilities (or utility divisions) to ensure the efficient protection of both the grid and power generation facilities.

8.2 Advanced Grid Technologies for Wildfire

Numerous technology investments are available to enhance the grid's performance, through software, hardware, or operational strategies. These technologies were originally developed for advanced grid functionality and reliability. States across the country are enacting policies that require the review of AGTs as part of integrated resource planning or other utility portfolio review mechanisms. In 2025 alone, 14 states passed legislation requiring the exploration of grid-enhancing technologies (Watt Coalition, 2025; Abernethy-Cannella and Murphy, 2025).

These same technologies also offer benefits for reducing wildfire risk. Utility WMPs demonstrate investment in real-time adjustments to line capacity (e.g., DLR), the installation of advanced conductors, and rapid fault detection and isolation technologies. In addition to "blue-sky" reliability benefits, these solutions reduce ignition risk, enhance operational flexibility, and limit the impacts that power shutoffs have on customers.

Table 2. Advanced grid technology (AGT) benefits by utility value.

Reliability Benefits of AGTs	Wildfire Benefits of AGTs
• Prevention of thermal overloads and line congestion. • Bidirectional power flow and integration of distributed, demand-side resources. • Fault detection and sectionalization to prevent high-impact cascading failures. • Optimization of power flow through the rerouting of electricity under changing grid conditions, such as generation variability or peak load congestion.	• Early detection, monitoring, and prevented escalation of wildfire-causing conditions. • Enhanced controls for efficient sectionalization and post-event recovery to ensure minimal service disruptions. • Optimized power delivery and maintenance of power quality during in-event periods.

Source: Adapted from Bhattacharya (2025).

AGTs have numerous benefits, as listed in Table 2. They can be helpful during pre-event planning for wildfire risk mitigation as well as during-event and post-event grid operation adaptation to minimize service disruptions and ensure reliable grid operations. The remainder of this section discusses how specific AGTs can help mitigate wildfire risks.

DLR is a crucial practice for managing power grids. Traditionally, power transmission and distribution lines operate according to static line ratings, which represent the maximum current they can carry. By contrast, DLR dynamically adjusts the thermal capacity rating of lines in real time according to environmental conditions and line characteristics, such as ambient temperature, wind speed, incident solar radiation, and conductor sag (Rostamzadeh et al., 2024). DLR models integrate wildfire characteristics and their associated heat into overhead line thermal ratings (Nazemi and Dehghanian, 2022). With elevated ambient temperatures, the system can maintain lines in an energized state as long as the conductor temperature remains below a defined limit (Rostamzadeh et al., 2024); after it surpasses this threshold, the line may be taken out of service (Trakas and Hatziargyriou, 2018; Nazemi and Dehghanian, 2022). In the pre-event phase, DLR can enable better preparedness by identifying lines that may be affected by wildfire risk, enabling proactive derating and/or reinforcement of vulnerable corridors.

DLR provides actionable intelligence to ensure system operators have the flexibility and foresight necessary to mitigate ignition risks while maintaining reliable service. By analyzing conductor clearance, sag profiles, and temperature excursions under varying weather conditions, DLR can identify the circuits most vulnerable to ignition. This informs proactive asset management decisions such as vegetation clearance, pre-season equipment upgrades, or power rerouting to lower-risk corridors. Importantly, DLR supports predictive risk modeling when integrated with weather forecasts, allowing operators to test the impacts of extreme fire weather on conductor safety margins. Modeling can help identify lines that may require temporary derating during a heat wave. DLR requires high-resolution datasets on environmental conditions and wildfire dynamics to support effective preparedness. Utilities must deploy and maintain robust sensor networks for real-time measurements, supplemented by weather stations and, increasingly, satellite-based wildfire detection feeds. Modeling the interactions between wildfire heat plumes and line conductors introduces computational complexity, often requiring advanced thermal modeling that integrates wildfire spread. Pre-event planning depends on the accuracy of risk forecasts—underestimation leaves lines vulnerable, whereas overestimation imposes unnecessary curtailments that affect reliability. Additionally, the capital cost of deploying DLR technologies may be prohibitive for smaller utilities. Thus, balancing cost, accuracy, and preparedness remains a central challenge for scaling DLR across wildfire-prone regions.

In addition to full-scale DLR systems, ambient-adjusted rating can also be employed as a simpler, lower-cost alternative to improve situational awareness and operational flexibility. Ambient-adjusted rating involves adjusting line ratings according to ambient temperature (or wind speed, in some implementations) rather than relying on continuous real-time sensor-based monitoring of conductor conditions. While less granular and accurate than DLR, the ambient-adjusted rating can still provide meaningful improvements over static seasonal ratings by more accurately reflecting prevailing weather conditions. However, its limited scope means that it cannot capture localized or transient thermal stresses. Consequently, the ambient-adjusted rating serves as a transitional step toward full DLR adoption, offering incremental reliability and safety benefits where a comprehensive sensing infrastructure is not yet feasible.

Similarly, topology optimization can aid in pre-event planning by reconfiguring network flows and enhancing operational robustness against anticipated wildfire risk. During the peri-event phase, DLR can enable operators to preemptively derate lines when real-time conditions indicate a high fire risk, thereby reducing the likelihood of contact events. During the post-event stage, DLR can enhance recovery by maximizing the usable capacity of surviving lines in real time, thereby accelerating service restoration. Again, topology optimization can enable flexible reconfiguration of the grid to bypass damaged infrastructure, prioritize critical loads, and support safe sequencing of restoration actions. Furthermore, AGT technologies can operate synergistically with complementary resources, such as energy storage, to enhance system performance across all three phases of wildfire events—before, during, and after. This coordination can be achieved through tailored optimization and control strategies that ensure efficient and resilient operation of diverse grid assets. Incorporating AGT technologies into grid operations requires not only the deployment of advanced hardware and communication systems but also the adoption of optimized investment strategies and the development of technical capacity among utilities and system operators. Achieving the full benefits of these technologies requires coordinated planning to determine where and when AGTs deliver the greatest operational value, while accounting for cost-benefit trade-offs, risk exposure, and system constraints. Moreover, operators need training and decision-support tools to interpret real-time data and implement adaptive control strategies. Strategic investment and workforce upskilling are therefore essential for ensuring AGTs are deployed effectively and integrated seamlessly into broader grid modernization efforts.

Future wildfire mitigation planning efforts will span multi-value investments to ensure the cost-benefit ratio of wildfire mitigation is optimized for customers.

8.3 Wildfire Fragility Curves or Functions

Fragility curves have long been established and used to quantify the probability of physical damage or asset failure for a given intensity of a specific hazard, such as earthquakes, wind storms, precipitation, and flooding. These curves plot the cumulative probability of damage to a component or an asset, showing the likelihood of reaching or exceeding a damage state as the hazard intensity increases. This makes fragility curves a very useful tool, enabling risk assessment, vulnerability analysis, and informed decision-making, such as determining which hardening measures to implement for critical infrastructure. Wildfire fragility curves are probabilistic tools used to assess the vulnerability of assets to wildfire hazards, in this case, electric grid assets and components (Nazemi et al., 2023). Unlike simple risk models that might use a binary “on/off” or “damaged/undamaged” approach, a fragility curve plots the probability of an asset failing or sustaining a specific level of damage against a range of fire intensity measures. For wildfire, these intensity measures can include wind speed, flame length, fire radiative power, and temperature. These curves are typically developed with a combination of historical data, physical modeling, and Monte Carlo simulations. For example, a fragility curve for a wooden utility pole might show a very low probability of failure at a low flame length, with the probability increasing significantly as the flame length and duration increase. The probability of failure would change further if consideration were given to fire-retardant wraps for the wood pole.

Wildfire fragility curves represent an area of emerging best practice, although much more research and testing are still required. Because fragility curves offer a more precise and data-driven approach to risk management, they enable better-informed quantification of the vulnerability of different asset types (e.g., wooden vs. composite poles and covered vs. bare conductors) to varying wildfire intensities, thereby informing strategic investment prioritization. In combination with operators, field crews, historical data, and consequence analyses, fragility curves can validate or reveal prioritizations for replacing or hardening assets, ensuring that capital is allocated where it will have the greatest impact on reducing ignition risk. Furthermore, fragility curves provide a quantitative framework for comparing the cost of a mitigation strategy (e.g., undergrounding a line) against its benefit in terms of reduced failure probability and avoided losses. This supports the creation of more defensible and economically sound WMPs. In another context, during an active wildfire event, fragility curves can be integrated into real-time and forecasted fire spread models. By combining a real-time fire forecast with the known fragility of assets in the fire's path, a utility can make more informed decisions about when and where to de-energize lines.

The development and implementation of wildfire fragility curves are areas of research need. Nazemi et al. (2023) developed an excellent approach; however, unlike data on asset failures from earthquakes, wind, and flooding, there is a relative lack of detailed, high-resolution data on how different grid assets respond to varying wildfire intensities and durations. This makes it difficult to create accurate and usable fragility curves. Furthermore, wildfire behavior is highly complex and depends on a wide range of factors, including meteorology, wind speed, terrain, fuel type, and fuel moisture level.

Chalishazar et al. (2023) have developed a framework to assess asset fragilities that capture the multiple dimensions needed to properly analyze wildfire threats. These dimensions include wildfire severity metrics (flame lengths), wildfire ignition potential, and even the probabilities of PSPS events. Although the fragility functions proposed in Chalishazar et al. (2023) are largely adaptable to include risks from other additional dimensions, they are currently most useful in the planning phase. It still lacks the temporal aspects that can make the fragility functions useful for real-time fire spread and temporally dynamic risk assessment. From the asset side, a range of variables, including asset type, age, maintenance history, health, and spatial and vertical positioning, are required. Given the numerous variables, it is clear that traditional two-dimensional fragility curves are inadequate for other hazard types. Therefore, multidimensional fragility functions, as proposed by Chalishazar et al. (2023), are required to capture not only the relevant variables but also their dynamic behavior over time. This is computationally intensive and requires advanced modeling expertise.

The objective is then to develop wildfire fragility functions that can be used, evaluated, refined, and ultimately adopted as an industry standard, which will require collaborative data sharing of asset performance during fire events. This would provide the critical mass of data needed to develop more robust and universally applicable fragility functions.

8.4 Customer Engagement

For many utilities, knowledge of the customer's specific electricity use is limited to the meter (i.e., volume and billing) and the customer class (i.e., residential, commercial, or industrial). Due to the potential for wildfire to disrupt electricity service, either by interfering with safe operations or by requiring manual de-energization to avoid ignition, a new level of customer engagement is required. Customer engagement related to wildfire involves a significant shift.

Pre-event, utilities are building greater knowledge around the criticality of electricity services to customers. For example, utilities now want to know which customers rely on electricity for medical needs, and which local electricity services support emergency response, such as fire, water services, and communications. Utilities are also partnering with local fire response and other emergency services to connect customers with resources to protect their homes and prepare for either a wildfire itself or a power disruption caused by one. Utilities are notifying customers about the potential for a power disruption to avoid ignition (PSPS) and what to expect—how the notice will arrive, likely timeframes, and who to contact. These advanced messages help set expectations and allow customers to ask questions before an event arrives.

Oregon requires outreach for functional needs but acknowledges a range of specialized engagement and outreach strategies for customers affected by wildfire-caused disruptions (Oregon Secretary of State, 2022). Customers with medical or access and functional needs are prioritized for notifications, potentially including outbound live-agent calls (Rocky Mountain Power, 2023; Xcel, 2024). Some states, such as California, have set broad guidelines beyond wildfire for outreach to customers with dependencies on medical equipment.

During an event, new mechanisms for customer communication are created. These notices warn customers of impending power shutoffs, adopting a proactive rather than reactive approach to power outages. Some utilities, such as Puget Sound Energy, provide a special "PSPS" category on their online outage maps. The state of Oregon provides explicit procedures in its rules regarding customer, critical facilities, and partner emergency services for de-energizing lines (Oregon Secretary of State, 2022).

Utilities may set up community resource centers to help customers during PSPS activations. Community resource centers may offer charging stations for mobile devices, access to information and status updates on the PSPS event, basic amenities such as bottled water, and Wi-Fi or internet access (SCE, 2023).

After an event, power restoration can take time due to the safety protocols of re-energizing the lines. Line crews walk the routes to assure safe restoration of power; UAS complement those walk-throughs. These important safety practices compound customer outage durations.

Proactive de-energization of electricity service challenges customer understanding, as there is no event, no wildfire, and because the decision-making for de-energization is internal to utility operations. Through utility and public agency communication, customer awareness is shifting to recognize the underlying cause of power disruptions. Yet at the time of this writing, public reporting mechanisms or records are limited for reporting on past PSPS events.

8.5 Reporting on Public Safety Power Shutoff (PSPS) and Ignition Events

Outages are typically reported through reliability oversight managers, and depending on their significance, details are provided. Large events will trigger NERC reviews and reports for root cause analysis. In general, preemptive de-energization is a standard tool for utilities to manage line conditions and ensure safety during maintenance or emergency situations. With wildfire, there is an expanded practice that will affect customers more regularly, even commonly, during high wildfire risk seasons, and will be carried out in accordance with individualized utility protocols. According to utility WMPs, one utility will have a different set of operating thresholds than its neighboring utility, yet the ultimate decision remains internal. While these independent protocols may be correct, it is challenging for external entities to validate or predict what happens in these scenarios. By administrative rules, there are no explicit requirements that WMPs include past PSPS events. Still, many WMPs address future events and practices, and to justify those decisions, they will reference lessons learned or past experiences.

One method for validation and greater consensus on practice is reporting after the event period. California requires utilities to report PSPS events annually and, through Commission order, may require more frequent post-event reporting (California Public Utilities Commission, 2021). These reports provide stakeholders with insight into the decision-making process and the activities taken to prevent PSPS. Oregon instructs utilities to file annual reports with the Commission and to post a non-confidential version of the report online; however, compliance is mixed (Oregon Secretary of State, 2022). At the time of writing, outside of California and Oregon, utility-based reporting is the only formal or general practice reporting mechanism. It is possible to recognize an event based on media reports and published customer testimonials; however, these offer a limited, non-technical perspective and are occasionally archived by the utility, summarized, and made available to the public.

As a result, it is known that PSPS events occur; however, there is no centralized, quantifiable source for both transmission and distribution systems. Regional voluntary reporting suggests that the vast majority of power disruptions related to wildfire are a result of automatic protection schemes (EPSS), and that of the percentage that are manual, most are responding to an active wildfire: only a small fraction are the result of avoiding ignition during conditions conducive to wildfire (WECC, 2025). Many transmission-level utilities are updating their PSPS policies to include reporting to the Open Access Same-Time Information System (OASIS), a web-available tool for sharing information on transmission operations, prices, and product availability (FERC, 2020). The reporting and availability of outage data for both transmission and distribution systems, focused on wildfire avoidance, enable these data to be combined with meteorological and fuel conditions, what-if scenario modeling, and more, helping refine future practices that can be shared amongst utilities.

Quantitative information on electric utility-caused wildfire ignitions (transmission or distribution) is sparse and incomplete, as there is no central ignition reporting database beyond what individual utilities collect for their own internal use or to comply with any existing state regulatory requirements. The National Interagency Fire Center's (NIFC) InFORM fire occurrence database currently provides a national-level source of historical to current data for wildfire ignition cause, that includes the class "Power Generation/Transmission" (NIFC 2025a). However, there are discrepancies in this data, and many causes of ignition are left as missing or undetermined, despite follow-on or independent investigations having determined a cause for some of these incidents.

A national, centralized reporting system for electric utility outages, public safety power shutoffs, and ignitions would be a valuable resource for 1) understanding conditions leading to wildfire ignition avoidance and its cost to system reliability, 2) determining the environmental and other risk factors that contributed to wildfire ignitions, and 3) aiding in future localized risk warnings, system operations, and mitigation actions. The aforementioned OASIS system is a possible reporting platform, though doesn't cover distribution systems (FERC, 2020). Alternatively, it is possible that this can be an extension to the newly developed National Emergency Response Information System (NERIS) system under the U.S. Fire Administration, where the data collection objective is to provide analytics to enhance future preparedness and response (U.S. Fire Administration, 2025).

8.6 Integrated Planning

Utilities are managing several types of risks in wildfire mitigation, including the potential for igniting wildfires, minimizing asset impact from a utility-caused fire, and withstanding non-utility-caused wildfires.

As proposed in this report, a resilience framework is a more effective and adaptive strategy for managing wildfire than a reliability framework. Reliability metrics and indices, such as the System Average Interruption Frequency Index and the System Average Interruption Duration Index, allow for “major event days.” Traditional concepts of reliability presume general operations; they are not a completely effective tool for managing wildfire risk reduction at this acute stage.

Wildfire mitigation planning is a significant investment planning process conducted separately from traditional planning paradigms, such as resource planning. However, the dominant activities (and expenses) involved in wildfire mitigation are system hardening and situational awareness in the distribution and transmission systems, which fall within the planning paradigm of risk reduction.

For example, general grid-hardening efforts benefit system reliability. Specifically, PG&E cites the co-benefits of wildfire mitigation for its capital investment projects. Many of the feeders with the highest number of customers experiencing multiple service interruptions are slated for hardening under the wildfire management strategy. Therefore, by aligning wildfire risk mitigation measures with other improvement projects, investment outcomes can serve a dual purpose.

With the growing prominence and prioritization of wildfire mitigation planning, a new crossover paradigm of integrated planning is expected to emerge. New methods for coordinated planning will highlight multi-value investments and offer more balanced and affordable pathways to meet essential goals.

8.7 Energy Efficiency, Wildfire Insurance Incentives, and Utility Wildfire Mitigation

Dominant utility investments to reduce ignition risk include infrastructure hardening, situational awareness, and vegetation management. Another area that could be explored to reduce the total liability of ignition risk—and improve customer conditions and costs—is energy efficiency measures.

Studies show that upgrading building shells and implementing active ventilation measures can reduce energy use, improve indoor air quality, and mitigate damage from wildfires and smoke. Insurance companies already offer incentives to building owners by reducing premiums for investing in these upgrades. In general, energy efficiency incentives offered to customers are within the utility's control and can accommodate a wider range of benefits, such as improved indoor air quality, water conservation, and the avoidance of local grid investments. As part of the measure design process, efficiency programs can consider bundling effects and local conditions, such as heating and cooling degree days. As utility wildfire mitigation programs mature, incorporating energy-efficiency incentive programs that account for wildfire mitigation will increase benefits for both customers and utilities (Kincaid, 2026).

8.8 Implementation Reporting and Cost Recovery Mechanisms

As the name implies, utility WMPs are plans. The most accurate insights into wildfire mitigation are gained during the reporting phase and are typically reflected in two places: the accounting report and the subsequent WMP.

As part of efforts to recover costs, utilities present an accounting for wildfire mitigation programs and actions to management, oversight boards, municipal governments, investors, or regulators (e.g., Avista Utilities, 2025). These accounting reports justify the costs associated with a given cost recovery mechanism, whether it is a tracker, balancing account, or automatic adjustment clause. Cost recovery also distinguishes between capital investments (such as the purchase of equipment) and operational costs.

WMPs may explain previous investments, rate progress toward their goals (e.g., reduction of a specific risk or targeted investment in a known wildfire-prone area), and describe a change in strategy from previous plans. They may record progress in both investments and improvements in the quality of their investments, such as reducing the impacts of PSPS (e.g., SCE, 2023).

As practices become more routine and stable, future mitigation programs may offer stand-alone implementation reviews. These reports support one of the WMPs' current purposes: making investment justifications and value propositions transparent to stakeholders, customers, and oversight entities. The stability of costs and practices will also eventually allow for more predictable treatment in a rate case.

8.9 Landscape-Level Partnerships

As noted in Section 7.5, utilities are only authorized to execute vegetation management activities within the limits of their ROW agreements. ROWs are narrow linear corridors that cross the landscape, often via easements with landowners. The agreements are designed to manage conflicting uses of the land. Of course, wildfire behavior has no recognition of easements and land ownership boundaries. Nor does it have any natural relationship to electricity service territories, which can also have unusual spatial dimensions and have no relationship to landscape characteristics. The term “pyrome” or “fire occurrence area (FOA)” describes a spatial unit within which the land will have shared characteristics for wildfire interactions (Archibald et al., 2013; Short et al., 2022). Pyromes or FOAs may be more appropriate units for planning wildfire mitigation (Tagestad, 2025).

Utilities are building up tremendous situational awareness of infrastructure conditions and on-site geospatial knowledge. They are also increasingly motivated and value-laden to participate, or even convene, neighboring landowners to manage wildfire holistically and even under an adaptive governance structure (Abrams et al., 2015; Huber-Stearns et al., 2021, 2022; Davis, 2025). These strategies are not only more effective at reducing wildfire risk, but they should also lower total costs. As wildfire mitigation programs mature and priorities escalate to states and local governments, multi-landowner partnerships for managing wildfire risk will become an essential practice. This practice and select examples are described in more detail in Section 3.8.4. In summary, it enables partners to coordinate efforts to reduce costs and wildfire risk, while balancing operational needs with environmental stewardship. The active coordination amongst utilities with state and Federal agencies has received increasing attention, but further action is required to streamline agreements and processes that can decrease environmental permitting times and resolve long delays to remove obvious hazardous vegetation in or adjacent to right-of-way corridors. As an example, the U.S. DOE's Bonneville Power Administration and the Western Power Marketing Administration have established MOUs with the U.S. Forest Service relating to transmission facilities on national forest system lands, outlining coordination for any work performed on transmission lines, including vegetation management. Efforts such as this should be examined for its structure and applicability to other agencies, both Federal and state, and utility types.

Activities carried out under these agreements can include joint vegetation-clearing projects to create defensible space or remove hazardous vegetation, the sharing of resources for monitoring and maintaining vegetation near ROWs, the implementation of cross-training programs between utility and partner organization crews, joint vegetation restoration and native species planting programs, joint forest thinning efforts to reduce fuel loads, conservation-focused agreements to improve biodiversity or wildlife habitat, and improvement in timeliness for reviews and permitting.

8.10 Instantiating Wildfire Resilience for Future Transmission and Distribution Siting

As the need for new transmission and distribution infrastructure approaches a critical point, it is worth exploring lessons from wildfire mitigation investments to inform better siting practices and right-of-way width standards based on underlying wildfire risk. While most utility wildfire mitigation actions involve retrofitting existing transmission and distribution systems, the underlying risk-mitigation approaches offer valuable insights for planning and siting future corridors and lines.

For transmission and distribution planning, modeling increasingly accounts not just for transfer paths and changes in power demand, but also for the ease or difficulty of new line routes and widths. Wildfire risk and features such as the wildland-urban interface can be incorporated into planning models to help avoid development in high-risk, fire-prone areas (Kumar et al., 2025). Infrastructure can also be proactively designed to integrate "resilient-by-design" principles, from IVM with wildfire-compatible vegetation in the powerline corridors, to installing grid technologies with embedded de-risking capabilities, to enhancing hazard risk monitoring, including placement of weather stations in higher risk areas, multi-modal early wildfire detection systems, regular and higher spatial density fuel moisture reporting, and vegetation health monitoring to improve electric utility operational capability and risk management activities (see Section 8.2; Brown et al., 2025).

These advanced activities should facilitate faster, more cost-effective siting authorizations and increase the value management of the asset over its lifetime.

8.11 Wide Availability Situational Awareness and Risk Forecasting

The development and wide availability of analytical situational awareness and risk forecasting tools are fundamental for consistent hazard monitoring and risk assessment. The decision space for grid operators is already incredibly complex and encompasses a range of factors across multiple time scales. Considerations for complex hazards, such as wildfire, further increase the complexity of the decision space. For situational awareness of wildfire hazard conditions and active wildfires, numerous publicly available, operational, national-extent models and datasets provide important information for decision-makers; however, none are integrated or geared toward use by the energy industry. By integrating information from various operational resources with full transparency and independent data access, currently fragmented technical capabilities can be transformed into decision-ready intelligence for utility operators. While many larger utilities have built their own systems to incorporate wildfire, many smaller utilities also need this capability but lack the resources or background to develop and apply it on their own.

There are ongoing scientific research efforts applying next-generation AI/ML to better quantify uncertainty and improve localized accuracy in wildfire predictions. For example, an ML-based surrogate model was developed to predict wildfire ignition risk by power lines and pinpoint network segments that may need to be de-energized based on sustained wind speed and gusts (Bayani et al., 2023). The model considers operational costs and the load served to prioritize low-cost lines and limit operations on high-risk lines. Another approach developed an ML model that incorporates not only meteorological data, topography, population density, and vegetation characteristics but also established indices as referenced above (e.g., National Fire Danger Rating System and the Canadian Fire Weather Index). The resulting model outperformed established indices in predicting wildfire ignition on a global scale (Shmuel and Heifetz, 2023). The limitations of an ML-based approach are that generated models perform best when they are built region-specific, rather than generally applied. The region-specific model development relies on robust observational datasets, including wildfire ignition and grid operation history, to properly train and develop the model. Promising advances in the field can be further developed and implemented by relevant agencies.

In summary, areas of need and emerging best practice include 1) locally tuned, national-extent multi-temporal, wildfire risk forecasting, 2) regular and higher spatial density fuel moisture reporting and assessment and vegetation health monitoring, 3) an evaluation of areas and temporal periods of emerging risk, 4) a common national utility-focused wildfire risk rating system, and 5) standardized, utility-focused risk mitigation metrics that span physical, operational, and human-factor state and actions.

9.0 References

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Appendix A Red Flag Warnings Supplement

There are many alternative forecast metrics to red flag warnings (RFWs) that should also be considered (Table A-1). A framework for using historical wildfires across the country to analyze the relationship between alternative metrics to RFWs provides a systematic approach to address regional variability in wildfire risk and bolster wildfire preparedness, resource allocation, and management. Rather than standardizing the metrics and underlying data used in every management zone across the country, standardizing the process by accounting for observed variability in fire behavior captures localized nuances and best supports preparedness.

Table A-1. Established weather-based forecast metrics, including each metric's primary source for obtaining access or further details, timescale, utility, and limitations.

Index	Source	Timescale	Utility	Limitations
U.S. Forest Service (USFS) Hot-Dry-Windy Index	Srock et al., 2018	Daily	Characterizes adverse weather conditions for extreme fire behavior to support fire management	Requires consideration of topography and fuels for full risk profile
USGS Wildland Fire Potential Index	USGS, 2025	Daily	Incorporates weather and vegetation data into a combustibility index for estimating potential flammability	Not intended to quantify ignition probability; has gaps in coverage
Canadian Forest Fire Danger Rating System Fire Weather Index	Van Wagner, 1987	Daily	Includes wildfire risk components for moisture, drought, spread, and buildup based on weather inputs	Does not directly incorporate topography or fuels; requires calculation
USDA-USFS National Fire Danger Rating System	Jolly et al., 2024	Daily	Considers fuel, weather, topography, and organizational readiness to provide a five-level adjective rating of fire danger	Weather data from Remote Automatic Weather Stations are sparse at high elevations and on slopes
National Interagency Fire Center (NIFC) 7-Day Significant Fire Potential	NIFC, 2025c	Weekly	Reveals service areas with high fire potential based on weather and fuel dryness to support resource coordination	Forecast uncertainty; broad spatial risk; potential non-ignition risk
NIFC Wildland Fire Potential Outlook	NIFC, 2025c	Monthly	Incorporates weather forecasts, drought, and fuels data into a probabilistic decision-support tool that enables seasonal planning across service areas	Forecast uncertainty; excludes shorter timescale events; broad spatial risk; potential non-ignition risk
Federal Emergency Management Agency National Risk Index	Federal Emergency Management Agency, 2025	Annually	Provides a strategic view of vulnerability and risk utilizing census data and wildfire modeling	Static forecast, broad spatial risk, relative vulnerability

In response to growing wildfire risk and the limitations of metrics like RFWs, utilities like Pacific Gas and Electric Company (PG&E) have developed their own indices. The PG&E system includes the Fire Potential Index and Wildfire Distribution Risk Models. The Fire Potential Index Model utilizes AI and machine learning to create an hourly index for ignition and spread with inputs of fuel moisture, vegetation, terrain, and historical ignitions in the service area. The Wildfire Distribution Risk Model considers the probability of ignition according to the relationship between outages and ignition likelihood, and it considers the impacts that wildfire has on infrastructure and communities to provide an annual view of risk per asset from grid-caused ignitions. As a larger utility in a risk-prone region, PG&E has the infrastructure and resources to invest in the development of proprietary indices for advancing wildfire resilience. However, similar utility-led efforts across all public, private, and cooperative utilities may prove challenging.

Pacific Northwest National Laboratory

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99354
1-888-375-PNNL (7665)

www.pnnl.gov