PG&E Wildfire Mitigation Plan R1

2026-2028 | Volume 1 of 2






Docket Title: 2026 to 2028 Electrical Corporation Wildfire Mitigation Plans
Docket #: 2026-2028-Base-WMPs

July 28, 2025

PACIFIC GAS AND ELECTRIC COMPANY
2026-2028 WILDFIRE MITIGATION PLAN

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PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 1

EXECUTIVE SUMMARY

1. Executive Summary

In the opening section of the Base Wildfire Mitigation Plan (WMP), the electrical corporation must provide an executive summary that is no longer than 10 pages. The electrical corporation must summarize the primary goal, plan objectives, and framework for the development of the Base WMP for the 3-year cycle. The electrical corporation may use a combination of brief narratives and bulleted lists.

Pacific Gas and Electric Company (PG&E or the Company) remains steadfast on our stand that catastrophic wildfires shall stop. Our 2026-2028 Wildfire Mitigation Plan (WMP) highlights this focus as we strive to stay ahead of the increasing wildfire risk facing California. Our primary goal for the WMP is to execute on our comprehensive strategy to reduce ignitions by implementing mitigations designed to minimize the likelihood of catastrophic wildfires, while also maintaining the reliability of the electric system and limiting disruptions to customers arising from our wildfire mitigation efforts.

Our WMP is built on our existing layers of protection rooted in a solid foundation of mitigations that we have put in place since 2019. The WMP incorporates insights, lessons learned, and emerging best practices from past WMPs, the 2023 and 2024 wildfire seasons, and our wildfire risk analysis in our 2024 Risk Assessment and Mitigation Phase (RAMP) report.[1]

California's changed climate is manifested through more frequent and severe wind events, periods of extreme precipitation, and intense hot/dry conditions. This hydroclimate "whiplash" creates rapid transitions between wet periods that promote vegetation growth and dry conditions that turn this vegetation into highly-combustible fuel, significantly increasing wildfire exposure.[2] These phenomena significantly amplify wildfire and reliability risks, increasing the urgency for more targeted and scalable mitigations.

Our 2026-2028 WMP implements both proactive and reactive measures to address wildfire risk. Our wildfire mitigation strategy includes preventing wildfire ignitions, swiftly responding to any ignition to limit the scale of any incidents and supporting efforts to improve forest health to reduce Wildfire Consequence (WFC). By combining advanced technologies, system upgrades, and collaborative efforts with communities and agencies, we aim to build resilient infrastructure and a safer environment.

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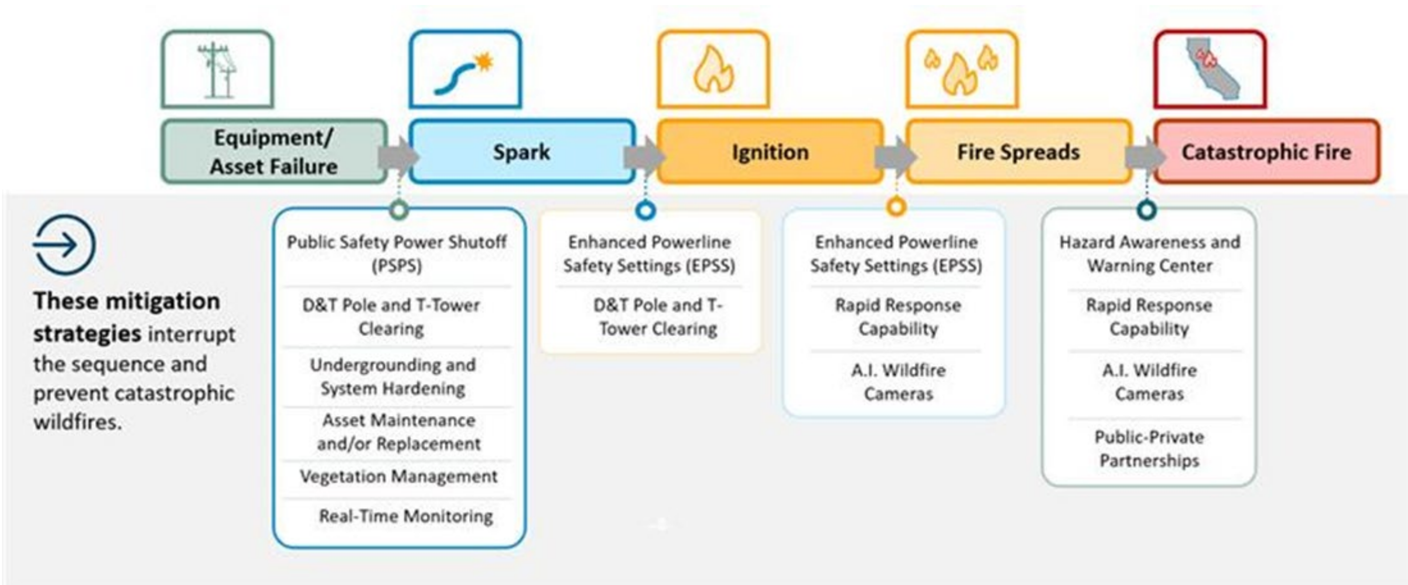
1 PG&E 2024 RAMP Report (May 15, 2024), Application (A.) 24-05-008.

2 Swain et al., *Hydroclimate Volatility on a Warming Earth,* Nature (Jan. 9, 2025), available at: <https://www.nature.com/articles/s43017-024-00624-z> (all hyperlinks in the entirety of this document were accessed on Mar. 10, 2025).

Interrupting the Wildfire Sequence

Wildfires tend to follow a predictable progression. Our wildfire mitigation strategy is designed to disrupt the wildfire sequence at various critical stages, effectively breaking the chain reaction that can lead to catastrophic fires. The work outlined in this WMP targets different steps in that sequence to halt fire development before it reaches an uncontrollable stage. Figure PG&E-1-1 below represents the wildfire sequence.

FIGURE PG&E-1-1:
WILDFIRE SEQUENCE



Mitigations to Prevent Ignitions

Our priority is to prevent ignitions in the High Fire Threat Districts (HFTD) and High Fire Risk Areas (HFRA) before they occur. Our preventive approach is two-fold: (a) deploy operational mitigations; and (b) undertake system hardening activities on the highest risk circuit segments to reduce ignition risk over the long-term.

Our operational mitigations such as Public Safety Power Shutoffs (PSPS), Enhanced Powerline Safety Settings (EPSS), and Downed Conductor Detection (DCD) are effective in providing weather-driven response to forecasted fire danger. Our key resilience mitigations—undergrounding and system hardening—will continue at a steady pace to provide more permanent risk reduction.

We are in the early stages of developing our real-time monitoring capabilities to identify the location of and resolve wildfire hazards before an ignition occurs.

Mitigations to Limit Wildfire Impacts

Recognizing that while we will strive to get to zero ignitions, it is prudent to build capacity to prevent an ignition from becoming a catastrophic fire. We do this in two ways: (1) containment measures such as pole clearing to remove fuel near utility infrastructure and public-private partnerships to remove vegetation fuel in forested areas and around communities; and (2) rapid response measures such as providing fire agencies access to PG&E's helicopter fleet to be used for aerial fire suppression and the sponsorship of wildfire cameras into the ALERTCalifornia network to facilitate early detection of a wildland fire.

WMP Objectives

Our objectives for the 2026-2028 WMP are to:

- Reduce the wildfire risk attributable to vegetation or other objects contacting PG&E's power lines through our comprehensive wildfire mitigation strategy, which includes both system resilience programs that provide permanent risk reduction and operational programs that reduce risk during periods of severe weather;
- Reduce the wildfire risk attributable to equipment failure through pole clearing, detailed inspection programs, and deploying new technologies that can quickly detect when a potential issue occurs on the system;
- Implement programs to limit customer disruption from our wildfire mitigation efforts, including reducing the scale and scope of outage programs; and
- Mature enterprise systems that support achievement of our risk reduction objectives by improving our systems, data accuracy and data governance practices.

WMP Framework

In 2026-2028, we will continue to leverage our foundational framework of risk-informed decision-making to minimize ignition risk and outage impacts. The framework of our wildfire mitigation portfolio includes four categories of mitigations to disrupt the wildfire sequence: (1) comprehensive monitoring and data collection; (2) operational mitigations; (3) system resilience; and (4) community support. The framework is summarized in Figure PG&E-1-2 below.

FIGURE PG&E-1-2:
PG&E'S 2026-2028 WMP FRAMEWORK

Risk Informed-Decision Making

Utilize risk models to identify and prioritize wildfire mitigation strategies to optimize risk buy-down and minimize customer impacts.

Comprehensive Monitoring and Data Collection

- Gain insight into the current state of our electrical systems to proactively identify ignition risk drivers
- Leverage Fire Detection Alerting System and Asset Inspections to Identify Risks

Operational Mitigations

- Manage existing system risk while system resilience activities are implemented
- Operational mitigations include vegetation management, PSPS, EPSS, and DCD

System Resilience

- Reduce risk in the HFTD and HFRA by changing how our electric system is constructed and operated
- System Resilience mitigations include undergrounding and overhead system hardening initiatives

Community Support

- Reduce customer and community impacts related to wildfire emergencies and PSPS and EPSS outages
- Host community engagement events to provide wildfire safety information before, during, and after wildfire events

Leveraging this framework, we have pinpointed 62 targets (quantitative and qualitative) that PG&E will track quarterly and annually. These targets focus on the most impactful actions to reduce wildfire risk and minimize customer disruptions from safety-related outages. In refining our strategy, we completed certain activities and restructured less-effective ones based on learnings over the past WMP cycles. Several actions identified with this WMP framework are highlighted below.

In response to Critical Issues RN-PGE-26-04, RN-PGE-26-06, RN-PGE-26-09, and RN-PGE-26-10, PG&E created four new targets for several initiatives. Additionally, we revised 17 targets in response to Critical Issues RN-PGE-26-04, RN-PGE-26-05, RN-PGE-26-06, RN-PGE-26-08, RN-PGE-26-10, RN-PGE-26-12. See 2026-2028 WMP Revision Notice Response R0 for more information.

Risk-Informed Decision Making

Our risk-informed decision-making relies on inputs from key wildfire risk models that are continuously improved and expanded. PG&E uses two types of models to address the dynamic wildfire risk across our service territory: operational models for operational mitigations such as PSPS and EPSS that show where fire risk is elevated in the short-term and long-term planning models for resiliency programs that permanently reduce risk by hardening the grid. The 2026-2028 WMP leverages the Wildfire Distribution Risk Model (WDRM) v4; this model is a significant evolution in our approach to quantifying the wildfire risk from overhead distribution assets. Utilizing Machine Learning (ML), the model combines enhanced event probability assessments and new models for several equipment classes with an upgraded WFC model. Similarly, we use the Wildfire Transmission Risk Model (WTRM) v2—which has seen similar step function enhancements—to help guide where to perform work on our transmission system. These enhancements ensure that our statistical approach to characterizing wildfire risk remains robust and adaptive.

Comprehensive Monitoring and Data Collection

The continued evolution of our asset and vegetation management (VM) inspection programs is targeted towards identifying locations that pose the highest risk for an ignition event. These programs evolved based on our learnings over the prior two WMP cycles.

The mature capabilities of wildfire cameras, weather stations and the Hazard Awareness Warning Center will continue to evolve as the underlying technology improves.

We are in the early stages of building real-time monitoring to obtain more dynamic insight into the state of our electric assets in response to accelerating weather volatility. In 2026-2028, we will mature these capabilities as we evaluate and integrate new technology into our grid infrastructure. Early examples of these are Early Fault Detection (EFD), Gridscope devices, and the next generation SmartMeter™ devices.

Operational Mitigations

PSPS, EPSS, and DCD are operational mitigations that provide a layer of protection for customers. While these programs are among the most impactful and cost-effective mitigations we deploy, they result in a reliability impact to customers. To address this reliability impact, we undertake initiatives to minimize the scope and duration of outages and support customers before, during, and after wildfire events.

System Resilience Mitigations

PG&E's system resilience activities are critical to permanently reducing wildfire risk, minimizing negative aspects of PSPS and EPSS, and strengthening the grid against extreme weather events. Overhead system hardening and undergrounding remain cornerstone initiatives in this effort. Since 2019, PG&E has undergrounded approximately 924 circuit miles of distribution lines. Building on this progress, PG&E will underground approximately 1,067 circuit miles of distribution lines between 2026 and 2028, effectively eliminating ignition risk in those areas and enabling resilience and reliability for other climate hazards such as high heat and more severe winter storms. Similarly, since 2018, PG&E has installed 1,230 miles of hardened overhead conductor. Building on this progress, PG&E will complete approximately 674 miles of covered conductor between 2026 and 2028, further enhancing system resilience in high-risk areas.

PG&E will continue the remote grid activity, through which PG&E removes overhead power lines and deploys standalone energy systems as an alternative or complement to system hardening. As of 2024, 11 remote grids are operational with 20 more in various stages of development.

Vegetation Management

PG&E continues to evolve its VM practices, using risk-informed planning to develop and execute on a portfolio of programs. Building upon lessons learned, PG&E plans to streamline its inspection programs while targeting high risk areas of the system to continuously reduce ignitions associated with vegetation. In 2026-2028, we will focus on consolidating VM distribution inspection programs, leveraging technology to enhance work execution, and utilizing operational analytics to better scope risk-informed work.

System Inspections

PG&E is consolidating the transmission inspection initiatives by integrating the aerial and ground-based methods under a single Transmission Detailed Inspection Program, aligning it with the distribution inspection activity. For distribution, PG&E introduced the Aerial Scan Inspection to enhance visibility of the highest-risk locations, supplementing detailed inspections with focused mid-span conductor assessments using drones. We will continue to leverage aerial inspections at scale, building on our 2024-2025 experience. Additionally, targeted infrared inspections will be deployed in areas of emerging concern to proactively address wildfire risk.

PG&E is also expanding quality control coverage to include detailed ground, aerial, and climbing inspections for transmission and distribution inspections.

Wildfire Resilience Partnerships

We have been pursuing various plans to catalyze targeted community and forest fire resilience aligned with locational risk drivers, aiming to mitigate the impacts and consequences of wildfires. These plans consider different forms of resilience partnerships which we are exploring, including facilitating fuels management within utility rights of way along likely wildfire pathways, creating expanded fuel breaks beyond designated rights of way, improving community and forest wildfire defenses, facilitating or co-funding roadside clearing under rights of way along key ingress/egress routes, and collaborative wood management. Since 2023, we have piloted several initiatives with nonprofit organizations and other entities to help drive localized landscape-scale treatment. In 2026-2028, we will continue to form new community partnerships, co-develop projects, and assess the associated benefits.

PG&E's Wildfire Mitigation Strategy Is Continuously Evolving

Since the rapidly-evolving wildfire risk can outpace mitigation efforts, we must continuously evolve and improve. A key lesson learned through the taskforce formed after the extreme July 2024 heatwave is that we must be ready to quickly adjust our mitigation activities to respond to emerging ignition risk. For example, we executed two additional initiatives to address elevated risk exposure: supplemental distribution pole clearing and deployment of Gridscope devices. Monitoring risk exposure is critically important. PG&E remains committed to continuously assessing evolving threats and maintaining a proactive, adaptive approach to wildfire mitigation.

PG&E is vigilant, learning from events both within and beyond our service territory. Evolving wildfire dynamics, including the increased threat of urban conflagrations, demand ongoing adaptation and innovation. As discussed in Section 13.2 below, we regularly engage in working group meetings with other investor-owned utilities in which we exchange information about our wildfire mitigations and discuss best practices. Given the broadening wildfire risk across the utility sector, sharing lessons learned with other utilities will help to strengthen industry-wide response.

Our 2026-2028 WMP details the significant progress we continue to make to reduce the risk of catastrophic wildfire for our customers and community. We realize, however, that the threat of catastrophic wildfire is evolving and increasing, and we must not stop innovating, learning, and evolving to adapt to this threat. We look forward to feedback from Energy Safety and stakeholders to help us achieve our mission to stop catastrophic wildfires in our service territory.

PACIFIC GAS AND ELECTRIC COMPANY
2026-2028 WILDFIRE MITIGATION PLAN
SECTION 2
RESPONSIBLE PERSONS

2. Responsible Persons

The electrical corporation must list those responsible for executing the Base WMP,[3] *including:*

- *Executive-level owner with overall responsibility;*
- *Program owners with responsibility for each of the main components of the plan; and*
- *As applicable, general ownership for questions related to or activities described in the Base WMP.*

Electrical corporations may not redact titles, credentials, and components of responsible person(s). This information must be publicly available.

Executive-Level Owner With Overall Responsibility:

Sumeet Singh, Executive Vice President, Operations and Chief Operating Officer

Program Owners:

Table PG&E-2-1 below lists the program owners with primary responsibility for each component of the WMP.

3 *Pub. Util. Code § 8386(c)(1)* – [Please note that all italicized footnotes are text quoted from Energy Safety's 2026-2028 WMP Guidelines.]

TABLE PG&E-2-1:
WMP SECTION PROGRAM OWNERS

Section	Title	Program Owner
Section 1	Executive Summary	Andy Abranches, Senior Director, Wildfire Risk Management
Section 2	Responsible Persons	Andy Abranches, Senior Director, Wildfire Risk Management
Section 3	Sections 3.1 – 3.5: Overview of the WMP	Andy Abranches, Senior Director, Wildfire Risk Management
	Section 3.6: Projected Expenditures	Kristin Manz, Vice President (VP), Finance and Planning
	Section 3.7: Climate Change	Andy Abranches, Senior Director, Wildfire Risk Management
Section 4	Section 4.1: Service Territory	Jadwindar Singh, Senior Director, Electric Asset Knowledge Management and Analytics
	Section 4.2: Catastrophic Wildfire History	Andy Abranches, Senior Director, Wildfire Risk Management
	Section 4.3: Frequently Deenergized Circuits	Mark Quinlan, Senior Vice President (SVP), Wildfire, Emergency and Operations
Section 5	Risk Methodology and Assessment	Andy Abranches, Senior Director, Wildfire Risk Management
Section 6	Wildfire Mitigation Strategy Development	Andy Abranches, Senior Director, Wildfire Risk Management
Section 7	PSPS	Mark Quinlan, SVP, Wildfire and Emergency Operations
Section 8	Grid Design, Operations, and Maintenance	Martin Wyspianski, VP, Electric Asset Management
Section 9	VM and Inspections	Angela Sanford, VP, Vegetation Management
Section 10	Situational Awareness and Forecasting	Scott Strenfel, Senior Director, Meteorology and Fire Science
Section 11	Emergency Preparedness, Collaboration, and Public Awareness	Angie Gibson, VP, Emergency Preparedness and Response
Section 12	Enterprise Systems	Tahir Paroo, Senior Director, IT Grid Systems and Smart Meter Operations
Section 13	Lessons Learned, Working Group Meetings, and Discontinued Initiative Activities	Andy Abranches, Senior Director, Wildfire Risk Management

Questions about any aspect of PG&E's 2026-2028 WMP should be addressed to: WMPDiscovery@pge.com.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 3

OVERVIEW OF BASE WMP

3. Overview of WMP

3.1 Primary Goal

Each electrical corporation must state the primary goal of its Base WMP. The primary goal must be consistent with California Public Utilities Code (Pub. Util. Code) Section 8386(a).[4]

California Pub. Util. Code Section 8386(a) directs the electric utilities to "construct, maintain, and operate electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment."

PG&E's 2026-2028 WMP includes a thorough analysis of our wildfire risk and a comprehensive strategy to reduce ignitions by implementing mitigations designed to minimize the likelihood of catastrophic wildfires while also maintaining the reliability of the electric system and limiting disruptions to customers arising from our wildfire mitigation efforts. Executing this strategy is the primary goal of this WMP.

3.2 Plan Objectives

In this section, the electrical corporation must summarize its plan objectives over the 3-year WMP cycle.[5] *Plan objectives are determined by the portfolio of activities proposed in the Base WMP.*

Plan objectives must address the electrical corporation's most highly-prioritized categories of wildfire risk drivers, as listed in *Section 3.4**.*

Electrical corporations must tie plan objectives to targets (both quantitative and qualitative) and performance metrics.

PG&E's objectives for the 2026-2028 WMP cycle are to continue to reduce the risk of wildfires associated with utility equipment through the execution of the mitigations discussed in this WMP. PG&E also seeks to minimize customer impacts associated with our mitigation initiatives, both in terms of operation and customer costs. PG&E's balanced wildfire risk portfolio is centered on the highest risk drivers for wildfires: equipment/facility failure, vegetation contact, and objects/animals contacting PG&E equipment. Our overall plan objectives can be summarized as follows:

1) Reducing the wildfire risk attributable to vegetation or other objects contacting PG&E's power lines by: (1) hardening overhead distribution equipment in our

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4 *"Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment." Pub. Util. Code § 8386(a).*

5 *Pub. Util. Code § 8386(c)(2).*

high-fire risk areas with either covered conductor or undergrounding; (2) maintaining vegetation clearance for trees and vegetation that could potentially contact our electrical facilities while also increasing the effectiveness of our VM work; (3) installing equipment to reduce ignition risks associated with animal/avian contact; and (4) assessing and deploying new technologies to continuously improve our risk mitigation efforts.

2) Reducing the wildfire risk attributable to equipment failure by: (1) continuing pole clearing; (2) performing annual asset inspections throughout our HFTD/HFRA; and (3) deploying new technologies that can detect when a potential issue occurs on the system.

3) Reducing the impact of PSPS outages on our customers by: (1) minimizing the scale of the events by additional sectionalizing of circuits; (2) enhancing Fire Potential Index (FPI) and weather modeling to improve PSPS criteria; and (3) installing system hardening to increase the resilience of our systems and reduce the need for PSPS events. Further, by addressing key risk drivers through our operational mitigations and System Resilience initiatives, and continually improving our situational awareness capabilities, we will minimize customer impacts from EPSS and PSPS.

4) Continuing to mature the enterprise systems that support achievement of our risk reduction objectives by improving data accuracy, implementing robust data governance practices, and pursuing integration of data inputs where possible.

PG&E’s objectives, risk drivers, targets and metrics for these risk drivers are summarized in Table PG&E-3.2-1 below.

TABLE PG&E-3.2-1:
LIST OF OBJECTIVES, RISK DRIVERS, TARGETS AND METRICS

Category	PG&E Target Name	Target Number	Objective #1 & 2: Reduce Wildfire Risk Associated With PG&E's Electrical Infrastructure			Objective #3	Objective #4	PG&E Performance Metric
			Vegetation Contact	Equipment Failure	Contact From Object	Reduce Customer Impact from Wildfire Mitigation Activities	Mature Enterprise Systems to Support Risk Reduction Efforts	
Grid Design, Operations, and Maintenance	System Hardening –– Undergrounding	GH-04	X	X	X	X		See Quarterly Data Report (QDR) Tables 5 and 6 for performance metrics[a]
	Overhead Hardening–- Distribution	GH-12	X	X	X			
	Line Removal Enabled by Remote Grid – Distribution[b]	GH-14	X	X	X	X		
	System Hardening Distribution Quality Assurance	GM-10D		X				
	System Hardening Distribution Quality Control	GM-11D		X				
	System Hardening –- Transmission Shunt Splices	GH-06		X				
	System Hardening –- Transmission Conductor Segment Replacement	GH-11		X				
	Service Breakaway Connectors	GM-14	X		X			
	Proactive Avian Abatement Feasibility Study - Transmission	GH-13			X			
	Detailed Inspection — Transmission	AI-04		X				
	Infrared Inspections –- Transmission	AI-06		X				
	Aerial Scan Inspections –- Distribution[b]	AI-07A	X	X				
	Detailed Inspections – Distribution	AI-07D	X	X				
	Evaluate/create new methods(s) to improve accuracy of Asset Inventory Data	ES-02		X				
	Asset Inspections Distribution Quality Assurance	GM-01D		X				
	Asset Inspections Transmission Quality Assurance	GM-01T		X				
	Open Tag Reduction –- Distribution Backlog	GM-03		X				
	Asset Inspections Distribution Quality Control	GM-09D		X				
	Asset Inspection Transmission Quality Control	GM-09T		X				
	Open Tag Reduction Distribution Backlog Quality Assurance	GM-12D		X				
	Open Tag Reduction Distribution Backlog Quality Control	GM-13D		X				
	Workforce Planning — Distribution Asset Inspection	GM-15		X				
	Updates on EPSS Reliability Study	GM-07	X	X	X			
	Integration of continuous grid monitoring technologies	ES-05	X	X	X			See QDR Table 10 for performance metrics[a]
	Continue sharing PSPS lessons learned	PS-10	X	X	X			
	Access and Functional Needs (AFN) Customer Support During PSPS Emergencies	PS-12				X		

TABLE PG&E-3.2-1
LIST OF OBJECTIVES, RISK DRIVERS, TARGETS AND METRICS
(CONTINUED)

Category	PG&E Target Name	Target Number	Objective #1 & 2: Reduce Wildfire Risk Associated With PG&E's Electrical Infrastructure			Objective #3	Objective #4	PG&E Performance Metric
			Vegetation Contact	Equipment Failure	Contact From Object	Reduce Customer Impact From Wildfire Mitigation Activities	Mature Enterprise Systems To Support Risk Reduction Efforts	
Vegetation Management and Inspections	Vegetation Management Critical Datasets Data Quality Remediation	ES-01	X					See QDR Tables 5 and 6 for performance metrics[a]
	Pole Clearing Program - Compliance[c]	VM-02C	X	X				
	Pole Clearing Program - Risk Reduction[c]	VM-02R	X	X				
	Substation Inspections — Distribution	VM-05	X					
	Substation Inspections – Transmission	VM-06	X					
	Substation Inspections – Power Generation	VM-07	X					
	Vegetation Management Quality Assurance — Distribution	VM-08D	X					
	Vegetation Management Quality Assurance — Transmission	VM-08T	X					
	Routine Transmission – Ground	VM-13	X					
	Transmission Hazard Patrol (Second Patrol, Tree Mortality)	VM-14	X					
	Integrated Vegetation Management Benchmarking	VM-25	X					
	Distribution Routine Patrol	VM-16	X					
	Distribution Hazard Patrol	VM-17	X					
	Vegetation Management Quality Control -— Distribution Routine	VM-22D	X					
	Vegetation Management Quality Control -— Pole Clearing	VM-22P	X					
	Vegetation Management Quality Control -— Transmission Routine	VM-22T	X					
	Wood Management Benchmarking	VM-23	X					
	Workforce Planning — Vegetation Management	VM-24	X					
	Mitigation of Legacy Tree Removal Inventory (TRI)[b]	VM-26	X					
Emergency Preparedness	Community Engagement — Outreach to HFRA Infrastructure Customers	CO-04				X		See QDR Table 10 for performance metrics[a]
	Community Engagement — Outage Preparedness Campaign	CO-05				X		
	Common Operating Picture Technology	EP-07				X		

TABLE PG&E-3.2-1
LIST OF OBJECTIVES, RISK DRIVERS, TARGETS AND METRICS
(CONTINUED)

Category	PG&E Target Name	Target Number	Objective #1 & 2			Objective #3	Objective #4	PG&E Performance Metric
			Reduce Wildfire Risk Associated With PG&E's Electrical Infrastructure			Reduce Customer Impact From Wildfire Mitigation Activities	Mature Enterprise Systems To Support Risk Reduction Efforts	
			Vegetation Contact	Equipment Failure	Contact From Object			
Situational Awareness and Forecasting	Line Sensor — Installations	SA-02					X	See QDR Tables 4 and 10 for performance metrics[a]
	Evaluate camera AI system performance and new functionalities.	SA-08					X	
	Distribution Fault Anticipation (DFA) Installations	SA-10					X	
	EFD - Installations	SA-11		X			X	
	Live Fuel Moisture Data Collection	SA-12					X	
	Weather Station Network Evaluation	SA-13					X	
	SmartMeter™ devices next generation capability evaluation	SA-14					X	
	Weekly uptime of Wildfire Cameras	SA-15					X	
	Weather Model Verification Tool	SA-16					X	
	Weather Model Enhancements leveraging AI-ML	SA-17					X	
	Weather Station Network Health	SA-18					X	
	Weather Station Network Optimization	SA-19					X	
Enterprise Systems	Grid Monitoring Sensor Systems Efficacy Assessment	ES-03	X	X	X		X	Not Applicable
	Operate and Maintain Weather Data Systems	ES-04	X	X			X	

(a) Attainment metrics (where applicable) are available on QDR Table 1.
(b) PG&E set new targets as a result of the Revision Notice for the 2026-2028 Base WMP, specifically in response to Critical Issues RN-PGE-26-04, RN-PGE-26-05, RN-PGE-26-06, and RN-PGE-26-09. See 2026-2028 WMP Revision Notice Response R0 for additional information.
(c) Pole Clearing Program Target (VM-02) is split into Pole Clearing Program – Compliance (VM-02C) and Pole Clearing Program – Risk Reduction (VM-02R) as a result of Critical Issue RN-PGE-26-10. See 2026-2028 WMP Revision Notice Response R0 for additional information.

The suite of mitigations[6] to address wildfire risk are described in Sections 7-11 of this WMP.

3.3 Utility Mitigation Activity Tracking IDs

Each electrical corporation must use "Utility Mitigation Activity Tracking IDs" (Tracking IDs) throughout its WMP. Each electrical corporation must implement a tracking system using Tracking IDs, as specified in the applicable Office of Energy Infrastructure Safety (Energy Safety) Data Guidelines, to tie targets, narratives, initiatives, and activities together throughout its WMP. The electrical corporation must use consistent Tracking IDs in its WMP submission and data submissions. Each Tracking ID must remain consistent across the 3-year WMP.

As specified in Energy Safety's Data Guidelines, PG&E uses Utility Mitigation Activity Tracking IDs (Tracking IDs) throughout this WMP to tie targets, narratives, initiatives, and activities together. These Tracking IDs will remain consistent throughout the 3-year WMP cycle.

3.4 Prioritized List of Wildfire Risks and Risk Drivers

The electrical corporation must provide a list that identifies and prioritizes all wildfire risks, and drivers for those risks, throughout its service territory.[7] The electrical corporation must use the format outlined in Table 3-1 below. Additionally, the list must include, at a minimum, the specific risks and risk drivers provided in Table 3-1. The electrical corporation must also add to its list any wildfire risks and risk drivers applicable to its service territory not already provided in the below table. Prioritization within Table 3-1 must be listed from highest priority to lowest priority.

The electrical corporation must also note topographical or climatological risk factors associated with each risk and risk driver.[8] Topographical and climatological risk factors may include, but are not limited to: elevation, slope, aspect, heat, aridity, humidity, wind, airborne salinity, precipitation (snow, rain, hail, etc.), and lightning. The electrical corporation must include how it determined these topographical and climatological risk factors via narrative (i.e., evaluating short-term/current conditions, long-term/future conditions).

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6 As used in this WMP, the term "mitigations" includes the activities that PG&E refers to as either mitigations or controls in the 2024 RAMP.

7 *Pub. Util. Code § 8386(c)(12).*

8 *Pub. Util. Code § 8386(c)(12)(B).*

Additionally, the electrical corporation must describe in a narrative accompanying Table 3-1 its basis for prioritizing these risks and risk drivers (e.g., "priority is assigned based on frequency, location with regard to the HFTD, and the expected consequence pertaining to the location"). This must also include a description of the timeframes used to evaluate the risks and risk drivers.

PG&E utilizes both California Public Utilities Commission (CPUC or Commission)-reportable and non-reportable ignitions to determine key risk drivers. The frequency of wildfires is assessed across 10 risk drivers. Each driver is discussed below.

- Equipment Failure: This driver is defined as events where failure of a PG&E asset, such as a conductor, arrester, insulator, breaker, transformer, caused an ignition.
- Vegetation Contact: This driver is defined as events where trees, tree limbs, and other vegetation contact a PG&E asset, resulting in an ignition.
- Contact From Object: This driver is defined as events where objects contact PG&E line equipment and create an ignition. This includes contacts by birds and other animals, mylar balloons, and vehicles.
- Unable to Determine: This driver considers events associated with PG&E assets which led to an ignition where the main driver of the ignition is undetermined.
- Contamination: This driver represents contamination events, which includes ignitions caused by batteries and contaminated insulators.
- Other: This driver includes failure events without known equipment causes.
- Wire-to-Wire Contact: This driver includes ignitions caused by wire-to-wire contact, commonly known as line slap.
- Seismic Scenario: This driver reflects failure events caused by seismic activity.
- Utility Work/Operation: This driver includes activities around utility processes.
- Vandalism/Theft: This driver reflects theft or vandalism from outside parties.

As discussed in Section 5.1.1, PG&E uses the bow tie methodology to evaluate risk events and prioritize risks and risk drivers consistent with the CPUC's Risk-Based Decision-Making Framework (RDF). The bow tie methodology provides: (1) a high-level visual summary of the risk event; (2) a detailed process for presenting the risk drivers; (3) the likelihood or frequency of the risk event; (4) the potential consequences of the risk event; and (5) the score for the assessed risk. Developing the bow tie methodology includes defining risk exposure, tranches, drivers, and consequences. Table 3-1 below identifies and prioritizes all wildfire risk drivers and sub-drivers.

TABLE-3-1:
LIST OF RISKS AND RISK DRIVERS TO PRIORITIZE

Priority	Risk	Risk Driver	Risk Sub-Driver	x% of Ignitions in HFTD/HFRA)[i]	Topographical and Climatological Risk Factors
1	Wildfire	Vegetation contact	Vegetation – Branch	12.5%	Extreme weather, wind
1	Wildfire	Vegetation Contact	Vegetation – Trunk	14.4%	Extreme weather, wind
1	Wildfire	Vegetation Contact	Vegetation – Other	6.9%	Extreme weather, wind
2	Wildfire	Equipment failure	Anchor/guy	0.1%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Capacitor bank	2.4%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Conductor	12.1%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Connector device	5.7%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Cross arm	1.7%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Fuse	3.4%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Cutout	See “Fuse”	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Insulator and bushing	1.5%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Lightning arrestor	0.7%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Pole	4.0%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Recloser	1.1%	Extreme weather, heat, wind
2	Wildfire	Equipment Failure	Relay	See “Sectionalized”	Extreme weather, heat, wind
2	Wildfire	Equipment Failure	Sectionalized	>0.1%	Extreme weather, heat, wind
2	Wildfire	Equipment Failure	Splice	See “Conductor”	Extreme weather, heat, wind
2	Wildfire	Equipment Failure	Switch	1.0%	Extreme weather, heat, wind

TABLE 3-1:
LIST OF RISKS AND RISK DRIVERS TO PRIORITIZE
(CONTINUED)

Priority	Risk	Risk Driver	Risk Sub-Driver	x% of Ignitions in HFTD/HFRA (2015-2024)[i]	Topographical and Climatological Risk Factors
2	Wildfire	Equipment failure	Transformer	1.7%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Voltage Regulator	0.6%	Extreme weather, heat, wind
2	Wildfire	Equipment failure	Other – Equipment failure	1.5%	Extreme weather, heat, wind
3	Wildfire	Contact from object	Animal Contact	9.6%	N/A
3	Wildfire	Contact from object	Balloon Contact	1.7%	Wind
3	Wildfire	Contact from object	Land Vehicle Contact	5.6%	N/A
3	Wildfire	Contact from object	Aircraft Vehicle Contact	See "Other – Contact from object"	N/A
3	Wildfire	Contact from object	Third Party Contact	See "Other – Contact from object"	N/A
3	Wildfire	Contact from object	Other – Contact from object	3.7%	N/A
4	Wildfire	Wire-to-Wire contact	N/A	1.5%	Heat, Wind
4	Wildfire	Contamination	N/A	2.1%	Precipitation, heat, wind
4	Wildfire	Protective device operation	N/A	See "Utility work/ operation"	N/A
4	Wildfire	Vandalism/theft	N/A	0.1%	N/A
4	Wildfire	Utility work/operation	N/A	0.3%	N/A
4	Wildfire	Lightning	N/A	See "All Other"	Precipitation, lightning
4	Wildfire	Unknown	N/A	1.4%	N/A
4	Wildfire	Dig-In	N/A	See "All Other"	N/A
4	Wildfire	All Other	N/A	1.4%	N/A

(a) Updated based on Substantive Errata filing on April 18, 2025 in accordance with Energy Safety issuance of Revision Notice at 21.

(i) The percentage of ignition in HFTD/HFRA is based on 2015-2024 data.

3.5 Performance Metrics

In this section, the electrical corporation must list the performance metrics, beyond those required by Energy Safety,[9] that the electrical corporation uses to evaluate the effectiveness of the plan in reducing wildfire and outage program risk.[10]

For each of these self-identified performance metrics, the electrical corporation must provide the following information in tabular form:

- *Associated WMP section (self-identified performance metrics can apply to the entire WMP; e.g., number of ignitions, number of acres burned, etc.); and*
- *The assumptions that underlie the use of the metric.*

PG&E will evaluate the effectiveness of the 2026-2028 WMP by using the Energy Safety performance metrics included in the QDR prepared by the utilities, pursuant to Energy Safety's guidance. Additionally, PG&E will apply the metric listed in Table 3-2 below as an indicator of progress towards our stand that "Catastrophic Wildfires Shall Stop."

TABLE 3-2:
SELF-IDENTIFIED PERFORMANCE METRIC

Performance Metric	Assumption that Underlies Use of the Metric	Section Associated With Performance Metric
Weather-Normalized CPUC-Reportable Fire Ignitions Rate in R3+ Conditions (Rolling 365 days)	(1) The metric focuses on ignitions occurring in elevated wildfire risk conditions as measured by the FPI of R3 and above; historical ignitions occurring in R3+ conditions result in the most consequential fires; (2) The rolling metric addresses the issue of considerable swings during the first half of the year when the number of R3 days is low (often 0)	WMP

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9 *The performance metrics identified by Energy Safety are included in the applicable Energy Safety Data Guidelines.*

10 *Pub. Util. Code §§ 8386(c)(4), (5).*

3.6 Projected Expenditures

The electrical corporation must summarize its projected expenditures in thousands of United States Dollars (USD) per year for the activities set forth in its 3-year WMP cycle in both tabular and graph form. For tabular form, the electrical corporation must follow the provided format in Table 3-3.

Energy Safety's WMP evaluation, resulting in either approval or denial, is not an approval of, or agreement with, costs listed in the WMP.

Table 3-3 summarizes our currently-projected expenditures per year for the 2026-2028 WMP cycle.

TABLE 3-3:
SUMMARY OF PROJECTED WMP EXPENDITURES
(THOUSANDS OF DOLLARS)

Year	Projected Spend
2026	$ 5,409,896
2027	$ 6,298,656
2028	$ 6,779,101

Note: Adjusted as a result of Revision Notice Response to Critical Issues RN-PGE-26-04 and RN-PGE-26-05.

Our wildfire mitigation costs are recovered through various cost recovery mechanisms, including the General Rate Case (GRC), the Electric Undergrounding Program application pursuant to Senate Bill (SB) 884, or other CPUC applications regarding wildfire mitigations. Decisions in these proceedings may lead to a revision of our WMP.

3.7 Climate Change

In this section, the electrical corporation must describe how it has considered dynamic climate change risks in writing its WMP.[11] *This description must include reference to the electrical corporation's most recent climate vulnerability assessment addressing new or exacerbated risks related to wildfire. This section is limited to two pages.*

While California has historically experienced large fires, in the last decade the state has experienced an increasing number of record-breaking wildfires and extreme swings in weather due to the impacts of a changed climate. These exceptional temperatures, in turn, impact the relative humidity of the atmosphere, increasing the occurrence of vapor pressure deficit that is also linked to more severe fires. These conditions also pose a health risk to vegetation, increasing the potential for branch or tree failures impacting our assets and creating potential sources of wildfire ignition.[12]

The WFC Model predicts the impact of an ignition event in terms of the potential hazard posed to life, property, and land. Consequence values are determined for the service territory based on simulated fire outcomes that use detailed fuels, weather, and topography data. Therefore, as the fuel mix and fuel moisture conditions change, the consequence models take this meteorology information into consideration.

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the CPUC's decision in the Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Rulemaking (R.)18-04-019).[13] The CPUC's methodology requires utilities to perform an assessment of all assets, operations, and services that will be impacted by future risks from climate change related to changes in temperatures, precipitation, and flooding, sea level rise, wildfire, and drought-driven subsidence. At a broader level, our CAVA assesses how climate change will impact the long-term likelihood of all wildfires to the Company's assets, operations, and services. However, it does not specifically consider the impacts of climate change to utility-caused ignitions, nor does it address the period covered in this WMP. Our 2024 CAVA used PG&E's HFRAs to assess exposure to climate-driven changes in wildfire conditions, as well as projections on acreage burned from the State's Fourth Climate Assessment.[14]

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11 *Pub. Util. Code § 8386(c)(3).*

12 Swain et al., *Hydroclimate Volatility on a Warming Earth,* Nature (Jan. 9, 2025), available at: <https://www.nature.com/articles/s43017-024-00624-z>.

13 Decision (D.) 20-08-046.

14 *California's Fourth Climate Change Assessment – Statewide Summary Report*, available at: <https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf>.

Additionally, there has been a rise in population and urban development in the Wildland Urban Interface (WUI).[15] These are areas where structures and other human development intermingle with undeveloped wildland. The WUI continues to expand in California.

As the threat of wildfire persists in our service territory, we have implemented operational mitigations based on fire potential to manage the wildfire risk. These operational mitigations, namely PSPS and EPSS, reduce the wildfire risk significantly during the year, but introduce negative reliability consequences which we are addressing through permanent risk reduction programs, as discussed in Section 7 and Section 8.2.2 below.

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15 Radeloff et al., *Rapid Growth of the US Wildland-urban Interface Raises Wildfire Risk*, Proceedings of the National Academy of Sciences of the United States of America (PNAS) (Feb. 6, 2018), available at: <https://www.fs.usda.gov/nrs/pubs/jrnl/2018/nrs_2018_radeloff_001.pdf>.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 4

OVERVIEW OF THE SERVICE TERRITORY

4. Overview of the Service Territory

In this section of the WMP, the electrical corporation must provide a high-level overview of its service territory and key characteristics of its electrical infrastructure.[16] *This information must provide Energy Safety with an understanding of the physical and technical scope of the electrical corporation's WMP. Sections 4.1-4.3 below provide detailed instructions.*

4.1 Service Territory

The electrical corporation must provide a high-level description of its service territory, addressing the following components:[17]

- *Area served (in square miles);*
- *Number of customers served; and*
- *Overview of electrical infrastructure.*

PG&E's service territory covers more than 72,000 square miles from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east. PG&E serves more than 5.7 million electric customers across 47 counties.

Table 4-1 below provides the high-level components of our service territory, including the area served in square miles, the number of electric customer accounts served, and an overview of our electrical infrastructure.

16 *Pub. Util. Code §§ 8386(c)(3), (8).*

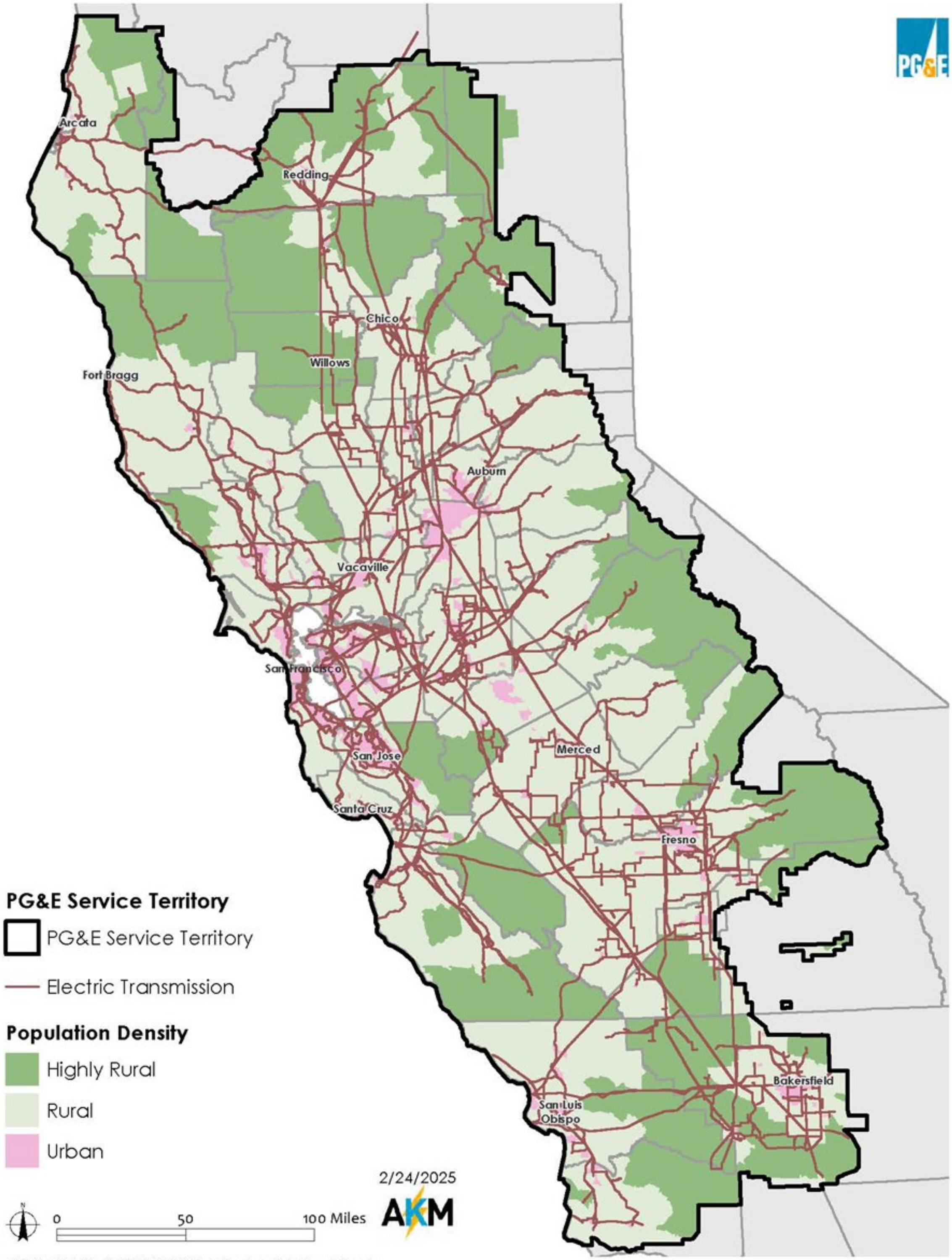
17 *Annual information included in this section must align with the applicable data submissions.*

TABLE 4-1:
HIGH LEVEL SERVICE TERRITORY COMPONENTS

Characteristic	HFTD Tier 2	HFTD Tier 3	Non-HFTD	Total
Area Served (Sq. Mi.)	31,907	6,141	34,693	72,741
Number of Electric Customer Accounts Served	361,698	170,740	5,225,042	5,757,480
Overhead Transmission Lines (Circuit Miles)	4,149	1,273	12,430	17,852
Overhead Distribution Lines (Circuit Miles)	17,771	6,754	55,241	79,766
Underground Transmission Lines (Circuit Miles)	11	1	171	183
Underground Distribution Lines (Circuit Miles)	2,491	1,063	25,544	29,098

Figure PG&E-4.1-1 below shows the square miles in our service territory that correspond to the population density for highly rural, rural, and urban customers. Some data is insufficiently large to show useful detail at the provided scale. See Appendix C for additional mapping related to this section.

FIGURE PG&E-4.1-1:
POPULATION DENSITY FOR HIGHLY RURAL, RURAL, AND URBAN CUSTOMERS



4.2 Catastrophic Wildfire History

The electrical corporation must provide a brief narrative summarizing its wildfire history for the past 20 years as recorded by the electrical corporation, California Department of Forestry and Fire Protection (CAL FIRE), or other authoritative government sources. For this section, wildfire history must be limited to electrical corporation ignited catastrophic fires (i.e., fires that caused at least one death, damaged over 500 structures, or burned over 5,000 acres). This includes catastrophic wildfire ignitions reported to the CPUC that may be attributable to facilities or equipment owned by the electrical corporation[18] *and where the cause of the ignition is still under investigation by the CPUC, CAL FIRE, and/or other authoritative government sources. The electrical corporation must clearly denote those ignitions as still under investigation. In addition, the electrical corporation must provide catastrophic wildfire statistics in the tabular form provided below, including the following key metrics:*

- *Ignition date;*
- *Fire name;*
- *Official cause (if known);*
- *Size (acres);*
- *Number of fatalities;*
- *Number of structures damaged;*
- *Estimated financial loss (USD); and*
- *Any lesson(s) learned.*

Table 4-2 provides the required format and the content for the tabulated historical catastrophic utility-related wildfire statistics.[19] *The electrical corporation must cite to an authoritative government source (e.g., CPUC, CAL FIRE, United States Forest Service (USFS), or local fire authority) for all data provided to the extent this information is available.*

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[18] *CPUC emergency reporting instructions: https://www.cpuc.ca.gov/regulatory-services/safety/emergency-reporting.*

[19] *Annual information included in this section must align with the applicable data submission.*

Since 2014,[20] PG&E has tracked and investigated 15 catastrophic wildfires as defined in Appendix A as “[a] fire that caused at least one death, damaged over 500 structures, or burned over 5,000 acres”[21] that *may* be attributable to facilities or equipment owned by the electrical corporation.

Table 4-2 below provides details about these 15 catastrophic wildfires PG&E has tracked and investigated. There has been no official cause determined for two of these fires (Sites and Mosquito). The data provided is based on information available to PG&E at the time of the 2026-2028 WMP submission.

TABLE 4-2:
CATASTROPHIC PG&E WILDFIRES

Ignition Date	Fire Name[(a)]	Fire Size (acres)	No. of Fatalities	No. of Structures Destroyed and Damaged	Financial Loss (in millions, USD)[(b)]
9/9/2015	Butte	70,868	2	965	$71
8/29/2017	Railroad	12,407	–	–	$3
10/8/2017	Nuns Complex	56,556	3	1,527	$47
10/8/2017	Cherokee	8,500	–	7	$1.4
10/8/2017	Atlas	51,624	6	903	$47
10/8/2017	Cascade	9,989	4	274	$7.75
10/8/2017	Redwood Valley	36,523	9	584	$23
10/8/2017	La Porte	6,151	–	76	$7.75
10/9/2017	Pocket	17,357	–	8	$47
11/8/2018	Camp	153,336	85	19,558	$16,650
10/23/2019	Kinkade	77,758	–	434	$950
9/27/2020	Zogg	56,338	4	231	$375
7/13/2021	Dixie	963,309	1	1,405	$1,150

20 In compliance with D.14-02-015, PG&E began tracking wildfires potentially associated with our electric facilities in 2014.

21 See Appendix A: Definition of “Catastrophic wildfire.”

TABLE 4-2:
CATASTROPHIC PG&E WILDFIRES
(CONTINUED)

Ignition Date	Fire Name[a]	Fire Size (acres)	No. of Fatalities	No. of Structures Destroyed and Damaged	Financial Loss (in millions, USD)[b]
9/6/2022	Mosquito[b]	76,788	–	91	Unknown
6/17/2024	Sites[b]	19,195	–	–	Unknown

(a) Data in this table comes from the CAL FIRE website (excluding financial loss). Financial loss information provided by CAL FIRE was combined for the Cascade and LaPorte Fires and the Nuns Complex, Atlas, and Pocket Fires. For those individual fires, the total financial loss is divided evenly.
(b) USFS is continuing to investigate the Mosquito Fire and CAL FIRE is investigating the Sites Fire. They have not designated an official cause of ignition for either fire.

Below in Table PG&E-4.2-1, we provide more information regarding the catastrophic wildfires listed above, including the official cause and lessons learned where available. This table includes the Mosquito Fire and the Sites Fire as fires that may potentially be attributable to electrical facilities, but remain under investigation. To avoid redundancy, this response will also serve as the response to the Section 13.1 request for lessons learned from any catastrophic wildfire ignited by utility facilities or equipment.

TABLE PG&E-4.2-1:
CAUSES AND LESSONS LEARNED FROM CATASTROPHIC WILDFIRES

Fire Name: Butte Fire	
Date of Ignition	**September 9, 2015**
Cause Based on Available Information	According to CAL FIRE, a gray pine contacted a PG&E powerline which ignited part of the tree. Embers from the contact with the conductor dropped into the fuels below the conductor, which ignited the wildland fire. Two gray pines on the outer edge of the pine stand had been previously removed, which left the interior gray pine that contacted the conductor more exposed to the sun and the powerlines.
Lessons Learned	At the time of the Butte Fire, PG&E did not have a process in place for evaluating specific lessons learned from individual fires. Since then, PG&E improved employee and contractor training for VM to mitigate wildfire and ensure safe work practices.
Fire Name: Railroad Fire	
Date of Ignition	**August 29, 2017**
Cause Based on Available Information According to the USFS	According to the USFS, a contractor was hired by USFS to remove a dead cedar tree adjacent to PG&E's powerlines in Madera County. After several cuts to the tree, it fell at an angle and hit PG&E's powerlines. After the tree hit the powerlines, the vegetation beneath the powerlines ignited. Given the presence of the downed lines, the crew could not safely attempt to put out the fire. Without immediate suppression efforts, the fire spread into the surrounding forest.
Lessons Learned	At the time of the Railroad Fire, PG&E did not have a process in place for evaluating specific lessons learned from individual fires. Upon review, the Railroad Fire did not result from an issue relating to PG&E's electric system. PG&E sent a crew to the area to mitigate a hazard tree to prevent a potential wildfire from occurring. The fire resulted from VM work that could have been performed more safely. After the Railroad Fire, PG&E improved its VM training and employee and contractor training regarding work outdoors in any forest, brush, or grass-covered land. In 2021, we implemented Safe Work Practices that outline safe work processes that contractors must adhere to when performing tree work. If tree work cannot be performed pursuant to the safe work practices outlined because of abnormal conditions, contractors are required to stop work to reevaluate how to perform the work safely.

TABLE PG&E-4-2.1:
CAUSES AND LESSONS LEARNED FROM CATASTROPHIC WILDFIRES
(CONTINUED)

Fire Name: October 2017 Wildfires	
Date of Ignition	**Various (see details below for each fire)**
Cause Based on Available Information According to the USFS	Vegetation contact and equipment failures in high winds caused these fires. Below we provide a high-level cause analysis for each fire based on available information. Cherokee – On October 8, 2017, PG&E observed that branches from a green, healthy California White Oak/Valley Oak tree had broken in Oroville. The troubleman who responded reported that one branch was found on the ground lying on top of a downed conductor. Another broken branch was suspended in the air, hanging on another branch, and touching a conductor that remained intact. Adobe – According to CAL FIRE, the Adobe Fire in Kenwood was one of six incidents constituting the "Nuns Fire," which ignited on October 8, 2017. When PG&E was granted access to the incident location, PG&E observed a green eucalyptus tree had fallen and was lying on three of three conductors of a 12 kilovolts (kV) primary tap line on the ground. The eucalyptus tree was rooted approximately 60 feet from the distribution conductors. Nuns – According to CAL FIRE, the Nuns Fire, which started on October 8, 2017 in Glen Ellen, consisted of six different fires: Nuns, Adobe, Norrbom, Pressley, Partrick and Oakmont. When PG&E was granted access to the incident site, PG&E observed that the top section of a green, healthy Alder tree had broken and was lying on the ground near one of three conductors of a downed open wire secondary service in Glen Ellen. Over a week later, two healthy Douglas Fir trees also came down on primary distribution conductors, and steel messenger cables supporting the telephone and Community Antenna Television conductors approximately 0.4 miles downstream from the initial ignition location. Sulphur – According to CAL FIRE, the Sulphur Fire started on October 8, 2017 in Clearlake Oaks. PG&E identified two poles that had broken. The top section of one pole had broken and fallen to the ground, and the pole one span to the west burned at the base and fell to the ground. This resulted in a wire down event. La Porte – According to CAL FIRE, the La Porte Fire started on October 9, 2017 in Bangor, Butte County. PG&E understands that CAL FIRE collected a section of conductor and a tree branch prior to releasing the incident location. After CAL FIRE released the incident location on October 13, 2017, PG&E accessed the site and was able to identify broken oak tree branches and a downed conductor at the incident location. Pressley – According to CAL FIRE, the Pressley Fire started on October 9, 2017 "east of Rohnert Park" in Sonoma County. Per CAL FIRE, this is one of the six fires that were included in the vegetation-caused "Nuns Fire." Norrbom – According to CAL FIRE, the Norrbom Fire was one of six incidents that make up the Nuns Fire, which ignited on October 8, 2017. On June 8, 2018, CAL FIRE issued a press release stating that the Norrbom fire was caused by a tree falling and contacting PG&E power lines. It is possible CAL FIRE was referring to a location on Gehricke Road, Sonoma, at which a black oak tree was found lying on downed conductors.

TABLE PG&E-4.2.1:
CAUSES AND LESSONS LEARNED FROM CATASTROPHIC WILDFIRES
(CONTINUED)

	Redwood Valley – According to CAL FIRE, the Redwood Valley Fire location was first observed on October 9, 2017. According to the CAL FIRE Investigation Report, a CAL FIRE employee reported a small vegetation fire on the east side of Hawn Creek Road. A PG&E troubleman recalled seeing one of three phases down near the incident location later in the day. Cascade – CAL FIRE determined the Cascade Fire, which occurred in Yuba County on October 8, 2017, was started by sagging power lines coming into contact during heavy winds. PG&E observed that the primary conductors were in place and appeared to be in working order at the time that CAL FIRE requested possession of the equipment. The secondary service line appeared to be damaged at mid-span, but there was no apparent damage to other PG&E facilities. Partrick – According to CAL FIRE, this fire occurred in Napa on October 8, 2017. When PG&E was granted access to the incident location, PG&E observed that a 20-inch diameter Coast Live Oak tree, approximately 50 feet tall and rooted approximately 40 feet uphill from distribution conductors had broken above its base. One of the two phases on a 12 kV tap line was on the ground. According to CAL FIRE, the Partrick Fire was one of six ignitions that were part of the “Nuns Fire.” Atlas – According to CAL FIRE, the Atlas Fire started in two locations in Napa on October 8, 2017. When PG&E was granted access to the first incident location, PG&E observed a broken tree limb and broken field-phase primary insulator on a 12 kV circuit. A green, healthy tree limb fell from a California White Oak/Valley Oak that was rooted approximately 15 feet from the distribution conductors. When PG&E was granted access to the second incident location, PG&E observed a California Black Oak tree that had broken at the base and was lying on the ground. The base of the California Black Oak tree was burnt and rooted approximately 20 feet from the distribution conductors. Lobo – According to CAL FIRE, the Lobo Fire ignited on October 9, 2017, near Nevada City. CAL FIRE removed both a Ponderosa Pine tree and distribution conductors at the incident location before releasing the incident location. Prior to CAL FIRE removing the tree, PG&E employees who assisted with the evidence collection reported briefly observing the pine tree resting on the conductors. PG&E does not know how the tree came to rest on the conductors because CAL FIRE removed the tree prior to PG&E having an opportunity to inspect the tree. Oakmont – According to CAL FIRE’s website, the Oakmont Fire started late on October 14, 2017. However, according to PG&E records, a PG&E troubleman who was at the Oakmont incident location to assist CAL FIRE on the evening of October 13, 2017 reported that there was already a quarter-acre grass fire with CAL FIRE on site working to contain the fire. When PG&E was granted access to the incident location on October 18, PG&E observed that a green, healthy Douglas Fir tree had uprooted and fallen onto other trees. Two of two phases of the 12 kV circuit were down on another tree, but the tree was still standing and not on fire.

TABLE PG&E-4-2.1:
CAUSES AND LESSONS LEARNED FROM CATASTROPHIC WILDFIRES
(CONTINUED)

Fire Name: October 2017 Wildfires	
Date of Ignition	**Various (see details below for each fire)**
Cause Based on Available Information	Pocket – According to CAL FIRE's website, the Pocket Fire started on October 9, 2017, in Geyserville. When PG&E accessed the incident location on October 17, 2017, PG&E observed that a top section of a California White Oak/Valley Oak tree had broken. At least one conductor of a 12 kV circuit was on the ground. The California White Oak/Valley Oak was rooted approximately 15 feet from the distribution conductors.
Lessons Learned	At the time of the October 2017 Wildfires, PG&E did not have a process in place for evaluating specific lessons learned from individual fires. For purposes of this response, we address the October 2017 wildfires collectively because they occurred over a relatively short period of time during significant high wind events. The identified ignitions primarily resulted from: (1) vegetation contact with electrical facilities; and/or (2) equipment failure. PG&E hired an independent firm to undertake a Root Cause Analysis (RCA) of each of the October 2017 wildfires to identify gaps that can be closed to reduce the risk of future catastrophic wildfires. Envista Forensics completed the RCA and published its report in July 2022. (c) PG&E responded to the Envista findings in August 2022. (d) PG&E agreed with the majority of the recommendations contained in that report, and referenced the work done by the Company since 2017 in the areas of risk assessment and mapping, situational awareness and forecasting, grid design and system hardening, asset management and inspections, VM and inspections, grid operations and protocols, data governance, emergency protocols, and PSPS.
Fire Name: Camp Fire	
Date of Ignition	**November 8, 2018**
Cause Based on Available Information	CAL FIRE investigators determined the cause of the Camp Fire was electrical arcing between an energized jumper conductor (power line) and the steel tower structure. Investigators determined a "C hook" that linked an insulator string connected to the jumper conductor to the transposition arm of a PG&E tower failed, allowing the energized jumper conductor to contact the steel tower structure. The ensuing electrical arcing between the jumper conductor and steel tower structure caused the aluminum strands of the conductor and a portion of the steel tower structure to melt. The molten aluminum and steel fell to the brush-covered ground at the base of the steel tower structure. This molten metal ignited the dry brush, which resulted in the fire. The broken "C hook" that led to the arcing showed substantial wear with age. The ignition occurred on a red flag warning day.
Lessons Learned	The lessons learned from the Camp Fire include: (1) the need for rigorous equipment inspections and maintenance; and (2) the need to use risk modeling to prioritize inspection and maintenance work so that maintenance is performed in the highest risk area for wildfires. In the enhanced inspection process, wear on C-Hooks and other equipment was specifically addressed.

TABLE PG&E-4-2.1:
CAUSES AND LESSONS LEARNED FROM CATASTROPHIC WILDFIRES
(CONTINUED)

Fire Name: Kincade Fire	
Date of Ignition	**October 23, 2019**
Cause Based on Available Information	The Kincade Fire ignited in the Geysers geothermal area in Sonoma County. According to CAL FIRE, a jumper cable on the Geysers #9 Lakeville 230 kV transmission line broke and arced upon failure toward the associated steel tower. CAL FIRE concluded this arcing ignited the vegetation below and ignited the fire. The portion of the transmission line connected to the broken jumper remained energized at the time of the incident though it had not served load to the neighboring Calpine-owned geothermal facility for several years. During the fire investigation, it was also determined that, following Calpine's request to remove the connection between the line and the Calpine-owned facility, the jumper cable had been configured as "open"—i.e., electrically connected at only one end, rather than both ends. According to CAL FIRE, due to this configuration, the jumper cables may have had a greater range of movement, potentially increasing the wear on the jumper cable at issue to the point that it failed during a wind event.
Lessons Learned	There were two primary lessons learned from the Kincade Fire: (1) the need to provide additional guidance on how to routinely evaluate whether facilities in the field are idle and need to be de-energized and/or removed; and (2) the need to provide additional guidance on the proper construction of open jumpers in order to prevent any undesired outcomes that may result from jumper conductor length or movement.
Fire Name: Zogg Fire	
Date of Ignition	**September 27, 2020**
Cause Based on Available Information	According to CAL FIRE, a gray pine near Zogg Mine Road in unincorporated Shasta County failed and struck PG&E powerlines. This contact resulted in an ignition of the vegetation beneath the powerlines. The ignition occurred on a RFW Day and quickly spread beyond the area of origin. The trees in the area where the ignition occurred had been inspected in 2018, 2019, and 2020. Photographs of the subject tree from PG&E's July 2019 Light Detection and Ranging (LiDAR) indicate the subject tree had a green canopy and appeared healthy, according to CAL FIRE's arborist expert.
Lessons Learned	Our analysis of the Zogg Fire led us to further evaluate the propensity for tree-related outages and overstrike tree potential, specifically during certain weather conditions such as RFW days, and to pilot programs to perform more detailed inspections of potential strike trees on routine VM patrols.

TABLE PG&E-4-2.1:
CAUSES AND LESSONS LEARNED FROM CATASTROPHIC WILDFIRES
(CONTINUED)

Fire Name: Dixie Fire	
Date of Ignition	**July 13, 2021**
Cause Based on Available Information	According to CAL FIRE, the Dixie Fire ignited in the Feather River Canyon when a tree failed and fell onto an overhead distribution line. As a result of the tree contact, fuses on two of the conductors operated, but the third fuse did not operate, and that line remained energized. The contact between the tree and the energized line eventually led to an ignition. CAL FIRE notes that at the time of the failure, the tree that contacted PG&E's powerlines was alive, vital, and growing vertically. Post-fire inspection suggested the tree had previous damage and decay that contributed to its failure.
Lessons Learned	Even on non-RFW days and/or days with no weather or wind events, an ignition can occur when vegetation or other objects contact an energized powerline. Outages in HFTD areas whose cause cannot be quickly ascertained may call for a more expedited response time even if there is not a known safety hazard, especially during summer months during times of drought.
Fire Name: Mosquito Fire	
Date of Ignition	**September 6, 2022**
Cause Based on Available Information	The cause of the Mosquito Fire is currently under investigation.
Lessons Learned	There are currently no lessons learned from this ignition because its cause is still under investigation.
Fire Name: Sites	
Date of Ignition	**June 17, 2024**
Cause Based on Available Information	The cause of the Sites Fire is currently under investigation.
Lessons Learned	There are currently no lessons learned from this ignition because its cause is still under investigation.

4.3 Frequently De-Energized Circuits

The electrical corporation must populate Table 4-3 and provide a map showing its frequently deenergized circuits.[22] *Frequently deenergized circuits are circuits which have had three or more PSPS events per calendar year. The table and map must include frequently deenergized circuits from the previous six calendar years (i.e., circuits that have had three or more PSPS events in at least one of the six previous calendar years).*

The table must contain the following; however, relevant information for an entry can be added as applicable:

- *Circuit ID Number;*
- *Name of Circuit;*
- *Dates of Outages;*
- *Number of Customers Hours of PSPS per Outage;*
- *Measures Taken, or Planned to Be Taken, to Reduce the Need for and Impact of Future PSPS of Circuit; and*
- *Estimated Annual Decline in PSPS Events and PSPS Impact on Customers.*

Table 4-3 includes circuits that were de-energized three or more times in a calendar year from 2019 to 2024. This table also includes the initiatives taken, or planned to be taken, to reduce the likelihood of PSPS events on those circuits. The table below is an excerpt; a complete version is in Appendix F.

[22] *Pub. Util. Code § 8386(c)(8).*

TABLE 4-3:
FREQUENTLY DE-ENERGIZED CIRCUITS

Entry #	Circuit ID	Name of Circuit	Dates of Outages	Numbers of Customers Hours of PSPS per Outage	Measures Taken, or Planned to Be Taken, to Reduce the Need for an Impact of Future PSPS of Circuit	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers (Customer hours)
1	152101101	ALLEGHANY 1101	10/9/2019	78,196	• 1.3 OH hardening miles in scope for 2026;	77,784 fewer customer hours of PSPS per year
			10/23/2019	18,513	• 4.4 miles in scope for undergrounding in 2026;	
			10/26/2019	100,496	• 0.3 miles in scope for undergrounding in 2028;	
			9/7/2020	59,913	• 1 Sectionalizing device added or replaced;	
			9/27/2020	34,140	• Mitigated by Temporary Generation;	
			10/14/2020	156		
			10/25/2020	64,061		
2	152101102	ALLEGHANY 1102	10/9/2019	9,611	• 0.4 OH hardening miles completed in 2021;	13,678 fewer customer hours of PSPS per year
			10/23/2019	6,415	• 10.6 miles in scope for undergrounding in 2025;	
			10/26/2019	21,576	• 2.6 miles in scope for undergrounding in 2026;	
			9/7/2020	6,269	• 21.2 miles in scope for undergrounding in 2027;	
			9/27/2020	3,111		
			10/25/2020	11,230		

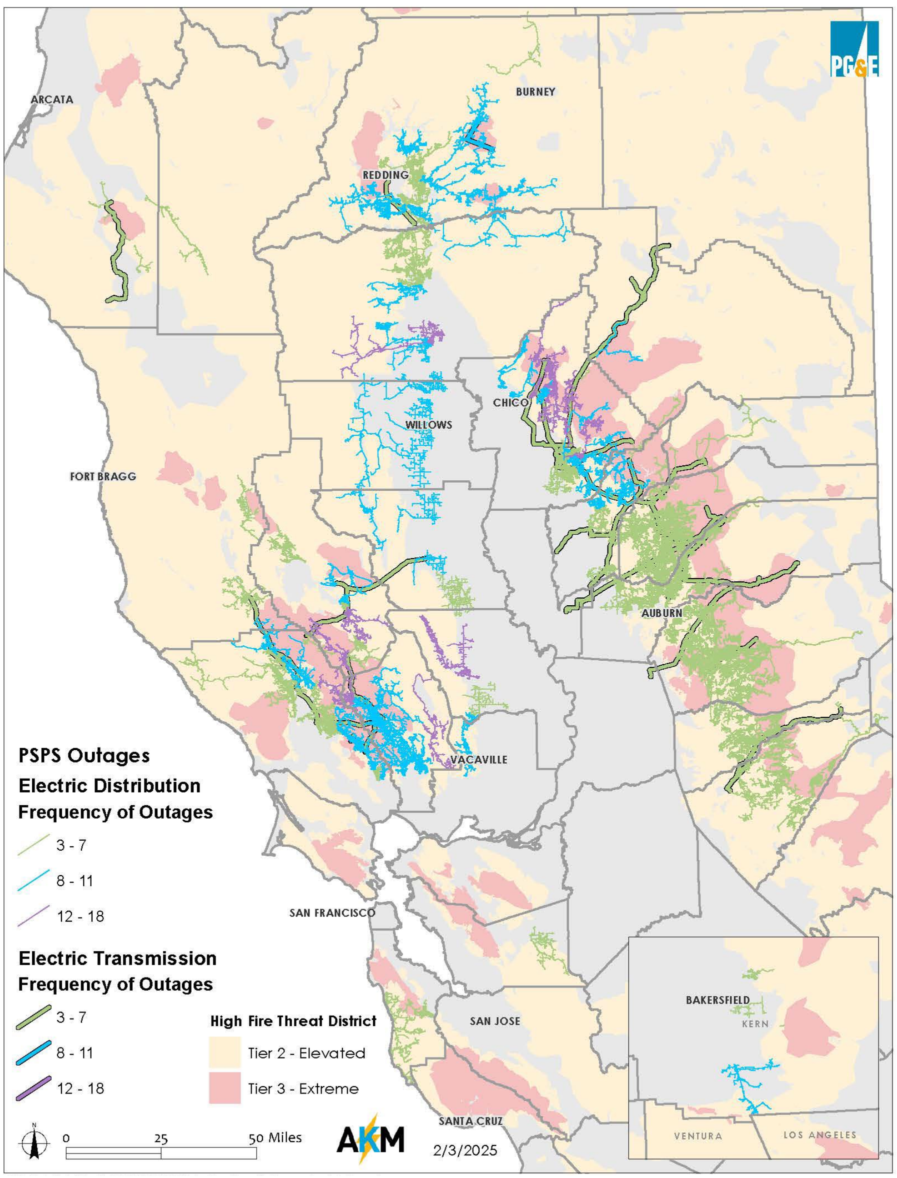
TABLE 4-3:
FREQUENTLY DE-ENERGIZED CIRCUITS
(CONTINUED)

Entry #	Circuit ID	Name of Circuit	Dates of Outages	Numbers of Customers Hours of PSPS per Outage	Measures Taken, or Planned to Be Taken, to Reduce the Need for an Impact of Future PSPS of Circuit	Estimated Annual Decline in PSPS Events and PSPS Impact on Customers (Customer hours)
3	163561101	ALPINE 1101	10/9/2019	3,184	• Mitigated by PSPS Protocols;	12,381 fewer customer hours of PSPS per year
			10/23/2019	7,437		
			10/26/2019	26,037		
			9/7/2020	11,735		
			9/27/2020	5,472		
			10/25/2020	13,664		
4	163561102	ALPINE 1102	10/9/2019	1,468	• Mitigated by PSPS Protocols;	13,047 fewer customer hours of PSPS per year
			10/23/2019	8,131		
			10/26/2019	28,571		
			9/7/2020	12,878		
			9/27/2020	5,959		
			10/25/2020	14,942		
5	103261103	ANDERSON 1103	10/9/2019	56,117	• 3 OH hardening miles in scope for 2025;	20,516 fewer customer hours of PSPS per year
			10/26/2019	15,846	• 3.7 miles undergrounded in 2023;	
			11/20/2019	4,616	• 2 Sectionalizing devices added or replaced;	
			10/21/2020	7,020		
			10/25/2020	12,569		
			8/17/2021	1,757		
			10/11/2021	1,834		

Activities that PG&E has undertaken to reduce the number of or scope of PSPS on these circuits include: (1) grid hardening, (2) annual updates to PG&E's PSPS protocols, (3) the installation of sectionalizing devices, (4) use of temporary generation, (5) addressing outstanding transmission tags, (6) transmission islanding, (7) transmission segmentation and (8) weather driven VM work.

Figure PG&E-4.3-1 is a map indicating the frequently de-energized circuits identified in Table 4-3. The circuits are colored by frequency of events. The map includes HFTD Tier 2 and 3 contour overlays. Some data is insufficiently large to show useful detail at the provided scale. See Appendix C for additional mapping related to this section.

FIGURE PG&E-4.3-1:
DE-ENERGIZED CIRCUITS BY FREQUENCY WITH HFTD CONTOUR OVERLAYS 2019-2024



PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 5

RISK METHODOLOGY AND ASSESSMENT

5. Risk Methodology and Assessment

In this section of the Wildfire Mitigation Plan (WMP), the electrical corporation must provide an overview of its risk methodology, key input data and assumptions, risk analysis, and risk presentation (i.e., the results of its assessment).[23] This section must provide the information necessary to understand the foundation for the electrical corporation's wildfire mitigation strategy. Sections 5.1-5.7 below provide detailed instructions.

The electrical corporation does not need to perform each calculation and analysis indicated in Sections 5.2, 5.3, and 5.6. However, if the electrical corporation does not perform a certain calculation or analysis, it must describe why it does not do so, its current alternative to the calculation or analysis (if applicable), and any plans to incorporate those calculations or analyses into its risk methodology and assessment in the future.

5.1 Methodology

In this section, the electrical corporation must present an overview of its risk calculation approach. This includes a concise narrative explaining key elements of the approach, one or more graphics showing the calculation process, and definitions of different risks and risk components.

5.1.1 Overview

The electrical corporation must provide a brief narrative describing its methodology for quantifying its overall utility risk, wildfire risk, and outage program risk (as described in Section 5.2.1 and defined in Appendix A). This methodology will help inform the development of its wildfire mitigation strategy (see Section 6). The electrical corporation must describe the methodology and underlying intent of this risk assessment in no more than five pages, inclusive of all narratives, bullet point lists, and any graphics. The electrical corporation must indicate and describe any industry-recognized standards, best practices, or research used in its methodology.

Wildfire risk is the highest risk on our risk register and is analyzed in the 2024 Risk Assessment and Mitigation Phase (RAMP). PG&E's risk assessment for wildfire begins with evaluating our overall utility risk from wildfires, Public Safety Power Shutoff (PSPS), and Enhanced Powerline Safety Settings (EPSS) for PG&E's service territory. PG&E uses the results of this analysis to:

[23] *Pub. Util. Code §§ 8386(c)(3), (8), (12)-(13), (17)-(18).*

- Understand the overall utility risk and associated risk components of Wildfire, PSPS, and EPSS events spatially and temporally across PG&E's service territory; and

- Develop and prioritize a comprehensive wildfire mitigation strategy, which is set forth in Section 6, to achieve our goal to stop catastrophic wildfires in our service territory.

PG&E's evaluation aligns with the California Public Utilities Commission (CPUC) Risk-Based Decision-Making Framework (RDF),[24] which builds on requirements for the utility risk assessment and mitigation framework adopted in the Safety Model Assessment Proceeding, Application (A.) 15-05-002. The RDF regulates the way California's large electric and natural gas investor-owned utilities assess and disclose risks that have safety, reliability, and financial consequences. The RDF increases transparency and accountability in the utilities' risk prioritization and mitigations. The RDF also provides Safety Policy Division (SPD) staff with a guideline and process for evaluating whether the utilities follow the CPUC's expectations and requirements for making risk-informed decisions.

In December 2024, PG&E achieved International Organization for Standardization (ISO) 55001 re-certification for demonstration of its conformance with the international standard for asset management. Some key aspects of the standard include risk identification and analysis; proactive risk management; balancing risk, performance, and cost; and continuous improvement while taking into account how these risks and opportunities may change over time. PG&E validated through this re-certification process that it has the processes and procedures in place to identify, evaluate, respond to, and monitor emerging and existing risks.

Figure PG&E-5.1.1-1 below provides an overview of our risk management process.

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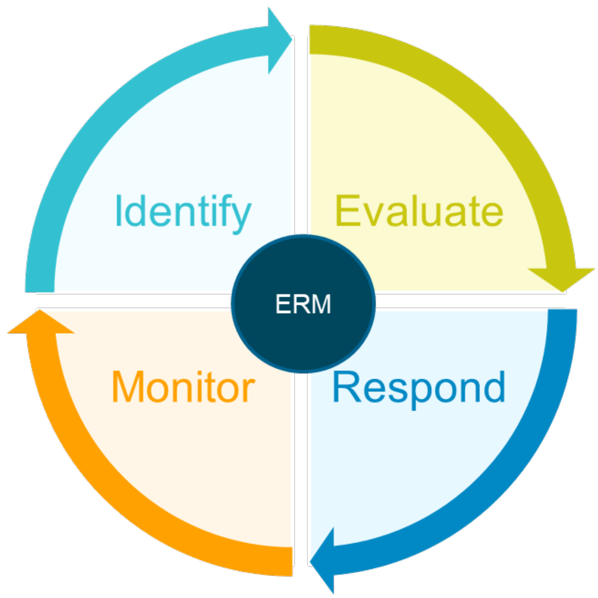
24 The RDF was approved in D.24-05-064.

FIGURE PG&E-5.1.1-1:
OVERVIEW OF OUR RISK MANAGEMENT PROCESS



Evaluation and Quantification of Wildfire, PSPS, and EPSS Risk

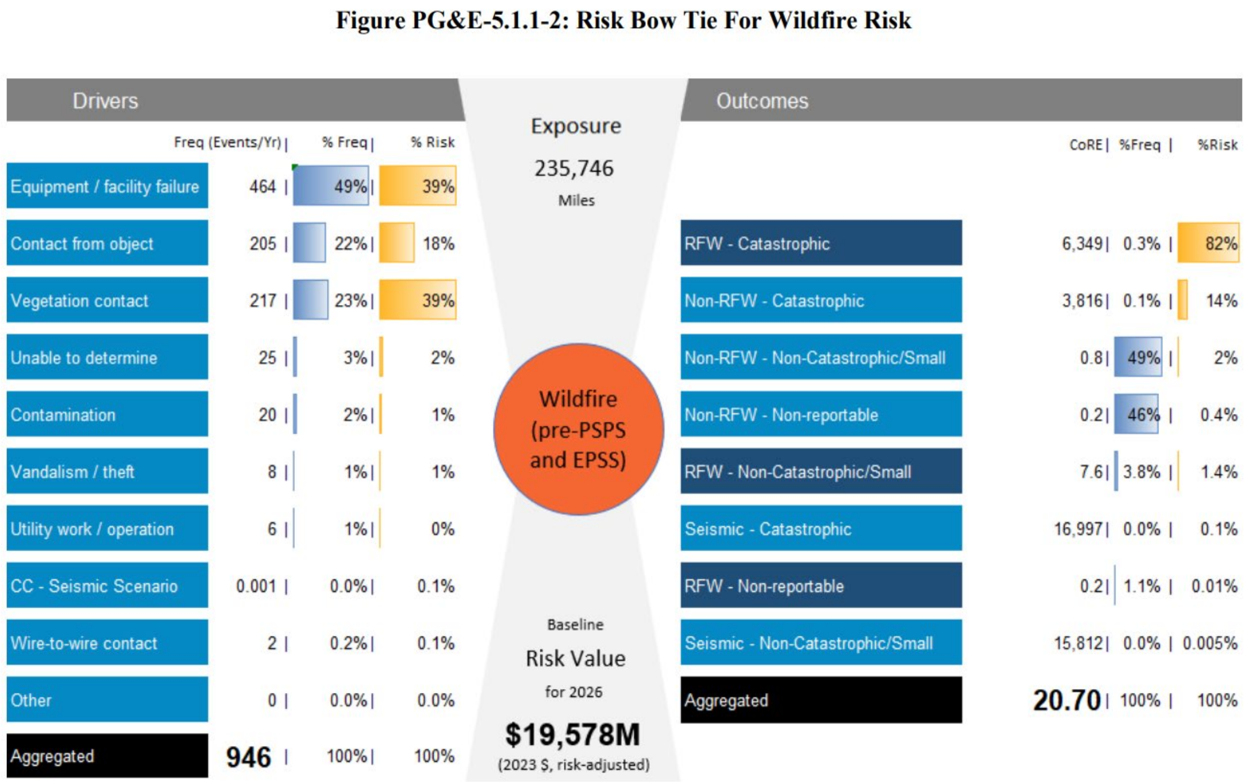
PG&E evaluates its enterprise risk using a Cost-Benefit Analysis (CBA), which puts a monetary value on risk associated with financial, safety, and reliability consequences. In terms of risk modeling, this strategy entails paying special attention to tail risk—the low frequency, high consequence events. We achieve this by using a risk-averse Risk Attitude Function (also known as a Risk Scaling Function), which gives a greater weight in the risk model to low frequency, high consequence events. For a comprehensive description of the risk modeling process, please see "PG&E Risk Assessment and Mitigation Phase Chapter 2 Risk Modeling and Cost Benefit Ratio" in the 2024 RAMP.

PG&E uses three models to evaluate PG&E's total utility risk (WLDFR, PSPS, and EPSS). PG&E's bow ties (Figure PG&E 5.1.1-2, Figure PG&E-5.1.1-3, Figure PG&E-5.1.1-4) provide a visual representation of the risk event, the drivers, driver frequency and risk contribution of the outcomes, outcome frequency, risk contribution and Consequence of a Risk Event (CoRE). In the center of the bow tie is the risk event, which is a well-defined, single observable, and measurable event. The three bow ties are presented below. The overall utility risk is an aggregation of these three risks and risk values as presented below.

$$\boldsymbol{Total\ Utility\ Risk\ Enterprise}\ (\boldsymbol{CBA\ Value}\ \$\boldsymbol{M}) = (\$17{,}227\text{M Distribution}+\$2{,}314\text{M Transmission}+36\text{M Substation}) + (\$1{,}953\text{M PSPS}) + (\$1{,}049\text{M EPSS}) = \$22{,}579\text{M}$$

- Wildfire Risk Model: Considers baseline risk without utilization of PSPS and EPSS operational mitigations. This is the Wildfire Risk that PG&E faces, based on its service territory and current assets. As additional system resilience mitigations are deployed, this baseline risk will decrease, as the expected frequency or consequence of wildfires will be reduced.

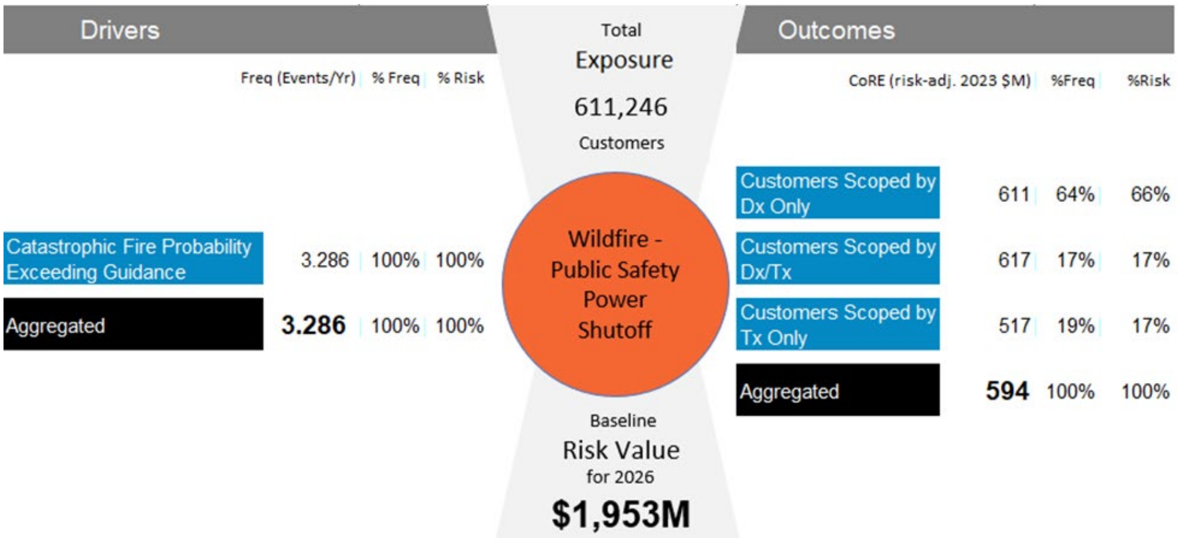
FIGURE PG&E-5.1.1-2:
RISK BOW TIE FOR WILDFIRE RISK



Note: Updated based on Non-substantive Errata filed on May 16, 2025 in accordance with Energy Safety's issuance of Revision Notice at 21.

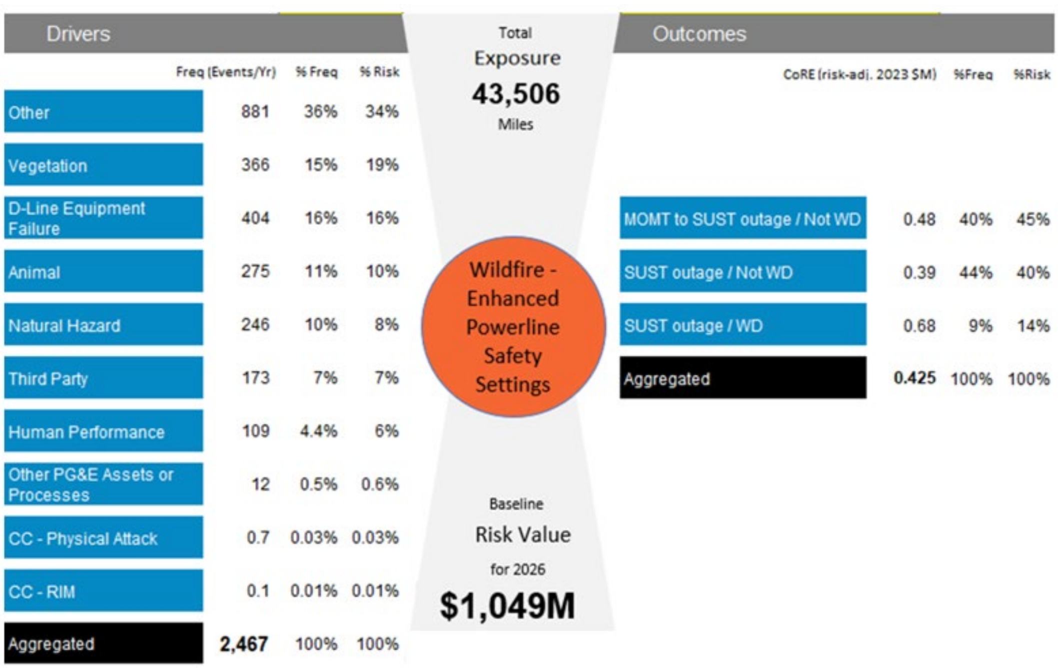
- PSPS Risk Model: Considers the negative impact of PSPS to customers. This is the risk that PG&E customers experience related to a "PSPS event," where lines are de-energized pre-emptively due to an incoming weather event and conditions that could otherwise lead to a catastrophic fire.

FIGURE PG&E-5.1.1-3:
RISK BOW TIE FOR PSPS RISK



- <u>EPSS Risk Model</u>: Considers the negative impact of EPSS to customers. This is the risk that PG&E customers experience related to additional outages from the enablement of the EPSS settings. These settings disable automatic reclosing operations and make protection devices more sensitive to fault currents to avoid a potential ignition.

FIGURE PG&E-5.1.1-4:
RISK BOW TIE FOR EPSS



Developing the bow-tie methodology includes defining risk exposure, tranches, drivers, and consequences.

- Risk exposure is the scope of the assessment we use to measure the risk. Examples of exposure include asset types that could be measured in line miles or asset counts. Exposure data is derived from records associated with outages, ignitions, and other failure mode data.

- Risk tranches include a group of assets, a geographic region, or other grouping with a similar risk profile such as having the same likelihood or consequence of risk events. Examples of tranches include circuits with high, moderate, or low reliability performance. Risk exposure is divided into different segments or tranches. More granular tranches allow for a better understanding of risk profiles. For example, for the wildfire risk on a system level, equipment failure is the largest cause of ignitions. However, when line miles in HFRA areas are considered separately, the largest risk driver becomes vegetation contact instead of equipment failure.

- Risk drivers are direct causes that lead to a risk event and indicate the likelihood or frequency of said risk event. Risk drivers include external events (such as vegetation contact) and characteristics inherent to the assets or systems (such as equipment/facility failure) which contribute to the risk event. Risk drivers can be broken into sub-drivers. For example, sub-drivers of the equipment/facility failure driver include conductor damage or failure, crossarm damage or failure, and pole damage or failure. For each driver and sub-driver, the Likelihood of Risk Event (LoRE) is quantified per unit of risk exposure for each tranche and then multiplied by risk exposure to produce the annual frequency of the risk event for that sub-driver/driver. Risk drivers can also lead to different outcomes if one driver is more likely to lead to a severe outcome than other drivers. Therefore, LoRE for each driver/sub-driver is further broken down into the likelihood of a risk event to result in each outcome.

- Risk consequences are potential impacts that could result if the risk event was to occur. Separating consequences into different outcomes allows for a better understanding of the chances of a high frequency/low consequence event or a low frequency/high consequence event. Consequences for each outcome are then evaluated for safety, reliability, and/or financial attributes. Specifically, for each outcome and tranche, the safety, reliability, and financial consequences are quantified using probability distributions in equivalent fatalities,[25] Customer Minutes Interrupted (CMI) and dollars, respectively, then aggregated into a single metric using the Cost-Benefit Analysis (CBA).

Once the Frequency of a Risk Event is quantified for each combination of sub-driver, outcome, and tranche, and CoRE is quantified for each combination of outcome and tranche of the bow-tie, the Risk Score is computed based on the multiplication of Frequency and CoRE. The outcome of the risk assessment is a bow tie for each risk,

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25 Equivalent fatalities are defined as the sum of number of fatalities and 0.25 times the number of serious injuries.

with each combination of bow-tie components (driver, sub-driver, outcome, tranche) quantified for Frequency, CoRE, and Risk Score.

5.2 Risk Analysis Framework

In this section of the WMP, the electrical corporation must provide a high-level overview of its risk analysis framework. This includes a summary of key modeling assumptions, input data, and modeling tools used.

At a minimum, the electrical corporation must evaluate the impact of the following factors on the quantification of risk:

- *Equipment/Assets (e.g., type, age, inspection, maintenance procedures, etc.);*
- *Topography (e.g., elevation, slope, aspect, etc.);*
- *Weather (at a minimum this must include statistically extreme conditions based on weather history and seasonal weather);*
- *Vegetation (e.g., type/class/species/fuel model, canopy height/base height/cover, growth rates, moisture content, inspection, clearance procedures, etc.);*
- *Climate Change (e.g., long-term changes in seasonal weather; statistical extreme weather; impact of change on vegetation species, growth, moisture, etc.) at a minimum, this must include adaptations of historical weather data to current and forecasting future climate;*
- *Social Vulnerability (e.g., Access and Functional Needs (AFN) populations, socioeconomic factors, etc.);*
- *Physical Vulnerability (e.g., people, structures, critical facilities/infrastructure, etc.); and*
- *Access Capacities (e.g., limited access/egress, etc.).*

PG&E’s risk models evaluate and define the total risk associated with wildfire, PSPS, and EPSS consistent with the RDF. This total risk is calibrated to our asset-level models. The asset-level models are used to calculate risk reduction for our wildfire mitigation programs. The remainder of this section refers to these PG&E planning models, including WDRM v4, WTRM v2, PSPS, and EPSS.

The application of the risk analysis framework, including risk driver selection, is shown for the Wildfire Distribution Risk Model version 4 (WDRM v4) in Figure PG&E-5.2-2 and for the Wildfire Transmission Risk Model version 2 (WTRM v2) in Figure PG&E-5.2-3. Note that the WDRM and WTRM, while sharing a common CoRE consequence model, apply different technical approaches that result in a different set of risk driver causal models for LoRE.

FIGURE PG&E-5.2-2:
WILDFIRE DISTRIBUTION RISK ANALYSIS FRAMEWORK

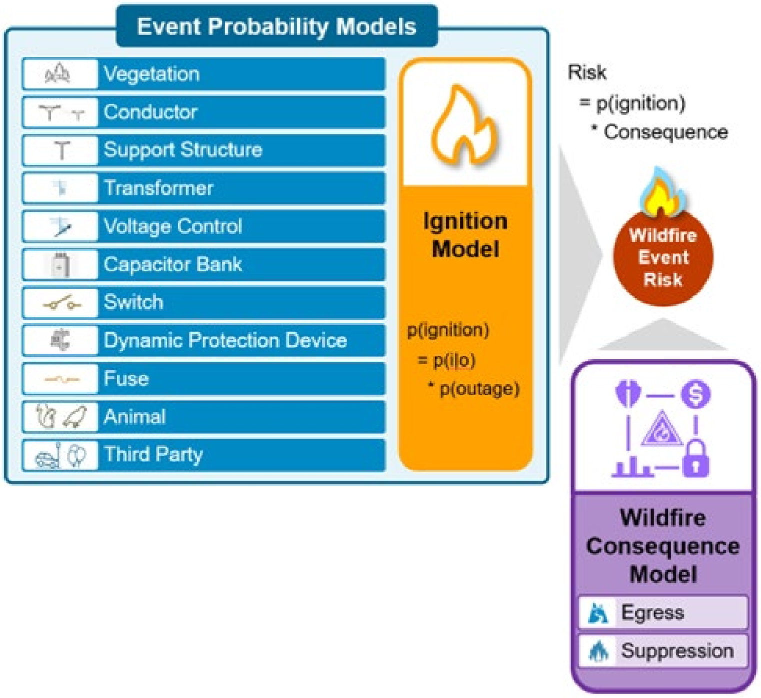


FIGURE PG&E-5.2-3:
WILDFIRE TRANSMISSION RISK ANALYSIS FRAMEWORK

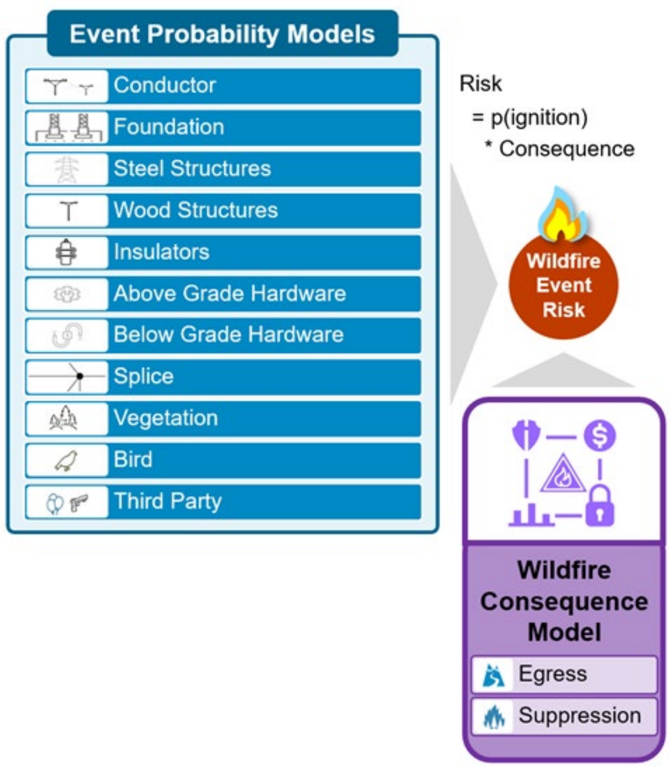


Table PG&E-5.2-1 below summarizes how we address key likelihood and consequence factors in our risk models.

TABLE PG&E-5.2-1:
ADDRESSING KEY LIKELIHOOD AND CONSEQUENCES IN RISK MODELS

Factor	How Key Factors Addressed in PG&E's Risk Models
Equipment/Assets	Threats to equipment and assets are considered in the LoRE analysis and quantification
Topography	LoRE and CoRE both use topographical data sets as they influence the threats and hazards to assets and the conditions for fire propagation
Weather	Hazards to assets and equipment due to weather are considered in the LoRE analysis and quantification. Weather also influences the CoRE assessment of wildfire propagation.
Vegetation	Hazard to assets in the probability of vegetation failures that can cause ignitions (LoRE analysis and quantification). Fuels quantification of vegetation is a key variable in the assessment of fire propagation.
Climate Change	Secondary input to hazards, threats with LoRE and fire propagation in CoRE. Not currently directly modeled.
Social Vulnerability	Demographic data used as an input for egress impact adjustment to CoRE.
Physical Vulnerability	Demographic data used as an input for egress impact adjustment to CoRE.
Access Capacities	Demographic data used as an input for egress impact adjustment to CoRE.

5.2.1 Risk and Risk Component Identification

In this section, the electrical corporation must provide a brief narrative and one or more simple graphics describing the framework that defines its overall utility risk. At a minimum, the electrical corporation must define its overall utility risk as the comprehensive risk due to both wildfire risk and reliability risk across its service territory. This includes several likelihood and consequence risk components that are aggregated based on the framework shown in Figure 5-1 below. The following paragraphs define each risk component.

While the overall utility risk framework and associated risk components identified in Section 5.2 are the minimum requirements for determining overall utility risk, the electrical corporation may elect to include additional risk components as needed to better define risk for its service territory. Where the electrical corporation identifies additional terms as part of its risk framework, it must define those terms. The electrical corporation must include a schematic demonstrating its adopted risk framework (similar to Figure 5-1), including any components beyond minimum requirements.

As shown in Figure 5-1, overall utility risk is broken down into two individual hazard risks:

- *Wildfire Risk: The total expected annualized impacts from ignitions at a specific location. This considers the likelihood that an ignition will occur, the likelihood the ignition will transition into a wildfire, and the potential consequences—considering* *hazard intensity, exposure potential, and vulnerability—the wildfire will have for each community it reaches; and*

- *Outage Program Risk: The measure of reliability impacts from wildfire mitigation-related outages at a given location.*

There are a minimum of nine intermediate risk components:

- *Wildfire Likelihood: The total anticipated annualized number of fires reaching each spatial location resulting from utility-related ignitions at each location in the electrical corporation service territory. This considers the ignition likelihood and the likelihood that an ignition will transition into a wildfire based on the probabilistic weather conditions in the area;*

- *Ignition Likelihood: The total anticipated annualized number of ignitions resulting from electrical corporation-owned assets at each location in the electrical corporation's service territory. This considers probabilistic weather conditions, type and age of equipment, and potential contact of vegetation and other objects with electrical corporation assets. This includes the use of any method used to reduce the likelihood of ignition. For example, the use of Protective Equipment and Device Settings (PEDS) to reduce the likelihood of an ignition upon an initiating event;*

- *Wildfire Consequence: The total anticipated adverse effects from a wildfire on each community it reaches. This considers the wildfire hazard intensity, the wildfire exposure potential, and the inherent wildfire vulnerabilities of communities at risk (see definitions in the following list);*

- *PSPS Risk: The total expected annualized impacts from PSPS at a specific location. This considers two factors: (1) the likelihood a PSPS will be required due to environmental conditions exceeding design conditions, and (2) the potential consequences of the PSPS for each affected community, considering exposure potential and vulnerability;*

- *PSPS Likelihood: The likelihood of an electrical corporation requiring a PSPS given a probabilistic set of environmental conditions;*

- *PSPS Consequence: The total anticipated adverse effects from a PSPS for a community. This considers the PSPS exposure potential and inherent PSPS vulnerabilities of communities at risk (see definitions in the following list);*

- *PEDS Outage Risk: The total expected annualized impacts from PEDS enablement at a specific location;*

- *PEDS Outage Likelihood: The likelihood of an outage occurring while increased sensitivity settings on a protective device are enabled at a specific location given a probabilistic set of environmental conditions; and*

- *PEDS Outage Consequence: The total anticipated adverse effects from an outage occurring while increased sensitivity settings on a protective device are enabled at a specific location, including reliability and associated safety impacts.*

There are a minimum of eleven fundamental risk components:

- *Equipment Caused Ignition Likelihood: The likelihood that electrical corporation-owned equipment will cause an ignition either through normal operation (such as arcing) or through failure;*

- *Contact From Vegetation Ignition Likelihood: The likelihood that vegetation will contact electrical corporation-owned equipment and result in an ignition;*

- *Contact From Object Ignition Likelihood: The likelihood that a non-vegetative object (such as a balloon or vehicle) will contact electrical corporation-owned equipment and result in an ignition;*

- *Burn Likelihood: The likelihood that a wildfire with an ignition point will burn at a specific location within the service territory based on a probabilistic set of weather profiles, vegetation, and topography;*

- *Wildfire Hazard Intensity: The potential intensity of a wildfire at a specific location within the service territory given a probabilistic set of weather profiles, vegetation, and topography;*

- *Wildfire Exposure Potential: The potential physical, social, or economic impact of wildfire on people, property, critical infrastructure, livelihoods, health, environmental services, local economies, cultural/historical resources, and other high-value assets. These may include direct or indirect impacts, as well as short- and long-term impacts;*

- *Wildfire Vulnerability: The susceptibility of people or a community to adverse effects of a wildfire, including all characteristics that influence their capacity to anticipate, cope with, resist, and recover from the adverse effects of a wildfire (e.g., AFN customers, Social Vulnerability Index, age of structures, firefighting capacities);*

- *PSPS Exposure Potential: The potential physical, social, or economic impact of a PSPS event on people, property, critical infrastructure, livelihoods, health, local economies, and other high-value assets;*

- *Vulnerability of Community to PSPS (PSPS Vulnerability): The susceptibility of people or a community to adverse effects of a PSPS event, including all characteristics that influence their capacity to anticipate, cope with, resist, and recover from the adverse effects of a PSPS event (e.g., high AFN population, poor energy resiliency, low socioeconomics);*

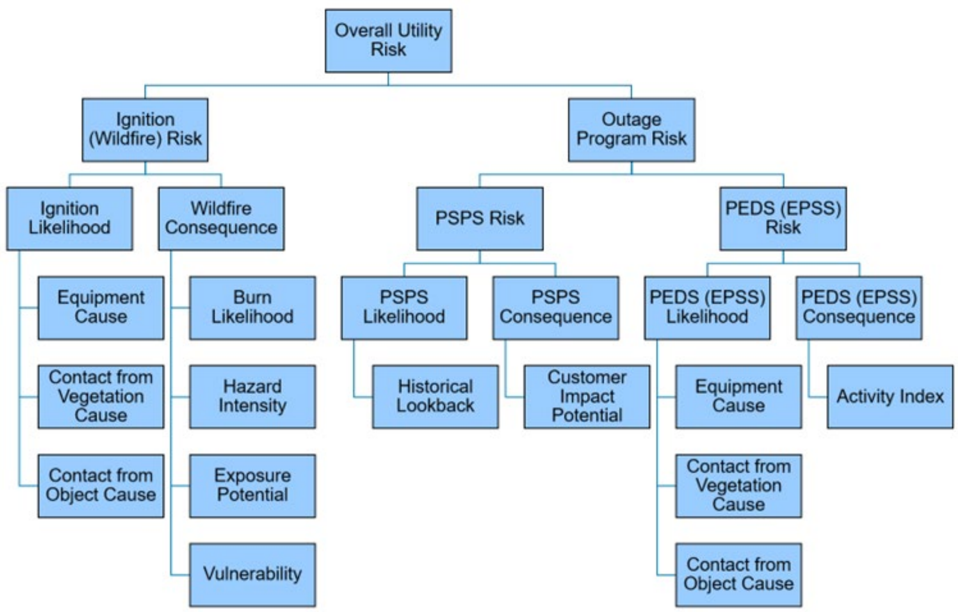
- *PEDS Outage Exposure Potential: The potential physical, social, or economic impact of an outage occurring when PEDS are enabled on people, property, critical infrastructure, livelihoods, health, local economies, and other high-value assets; and*

- *PEDS Outage Vulnerability: The susceptibility of people or a community to adverse effects of an outage occurring when PEDS are enabled, including all characteristics that influence their capacity to anticipate, cope with, resist, and recover from the* *related adverse effects (e.g., high AFN population, poor energy resiliency, low socioeconomics).*

The electrical corporation must adopt these definitions for this section of the WMP. If the electrical corporation considers additional intermediate and fundamental risk components, it must define those components in this section as well.

PG&E identifies the components of Overall Utility Risk based on Wildfire and Outage Program Risk, as required by the WMP Guidelines in Figure 5-1.

FIGURE 5-1:
COMPOSITION OF PG&E'S OVERALL UTILITY RISK



<u>Ignition (Wildfire) Risk Component Identification</u>

Following PG&E's general Risk Analysis Framework, the Ignition (Wildfire) risk model is broken into the following components:

- LoRE – Transmission;
- LoRE – Distribution; and
- CoRE – Wildfire Consequence (WFC).

LoRE – Transmission and Distribution Probability of Ignition

LoRE, for the wildfire risk models, is the probability of an ignition, or p(i), event resulting from the failure of a distribution or transmission asset during a fire season. Separate probabilities of ignition models are produced for transmission and distribution-related ignitions to account for differences in causal risk drivers that can be addressed by risk mitigation programs.

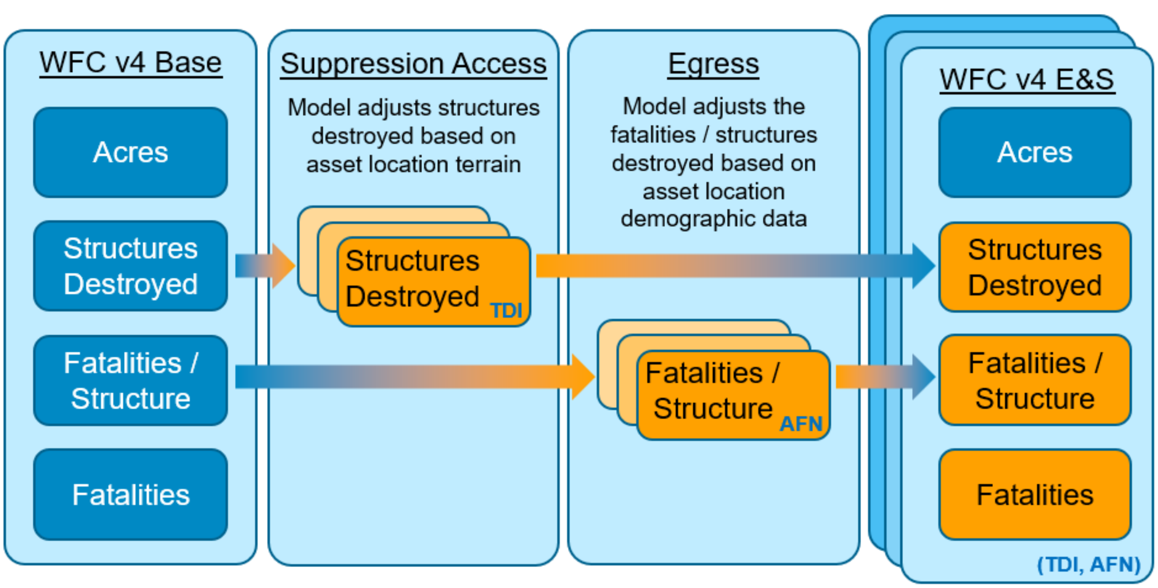
Both the transmission and distribution p(i) models use composites of causal models to reflect the various threats that cause asset degradation over time as well as the external hazards that can directly cause an electrical asset to fail. However, their framework implementations are different, with the transmission p(i) model using a combination of engineering first-principle calculations and machine-learning algorithms whereas the distribution p(i) model uses machine-learning algorithms only.

CoRE – WFC

The WFC Model estimates the likely impact from an asset ignition event in terms of damages and hazards posed to people, structures, and the natural environment. The WFC encompasses both the Burn Probability and the WFC components for Hazard Intensity, Exposure Potential, and Vulnerability as identified in the WMP Guidelines. Our perspective is that the Burn Probability is a deterministic assessment of local conditions at the time of an ignition event rather than a probabilistic outcome.

The WFC estimates the consequence value for a location based upon average historical fire season conditions for fuel and weather. Consequence values are adjusted for Egress impacts based on local demographic characteristics and for fire suppression impacts using local terrain and infrastructure attributes. Figure PG&E-5.2.1-1 provides an overview of the WFC components.

FIGURE PG&E-5.2.1-1:
WFC v4 COMPONENTS



Outage Program Risk Component Identification

Outage Program Risk is determined from two components, PSPS Risk and PEDS, also known as EPSS, Risk. The Outage Program risk is reported on a circuit segment basis so that the risks can be summed with the Ignition Risk values to determine Overall Utility Risk.

PSPS Risk Components

The PSPS Consequence Model is a spatial representation of the PSPS risk as aggregated from our customers to our circuits, so that we can understand the PSPS risk in high-risk locations based on frequency, customer, and duration of PSPS impact. It is informed by a 12-year lookback and the enterprise PSPS bow tie model that evaluates safety, reliability, and financial consequences. The PSPS Consequence Model contains a customer classification weighting that includes medical baseline and life support customers. The customer weighting is established to identify and prioritize customers and circuits that include vulnerable customer populations.

The basis of the model is a 12-year customer lookback that is informed by two meteorology models (Fire Potential Index (FPI) and Ignition Potential Weather (IPW)), to show how historical weather events would impact customer reliability based on current system equipment configuration. The models use PSPS guidance criteria to perform a back-cast using our 30+ year climatological dataset.

Risk drivers that the FPI models account for include fire weather parameters (wind speed, temperature, and vapor pressure deficit), dead and live fuel moisture data, topography, and fuel type data to predict the probability of a large and/or catastrophic ignition.

Risk drivers that the IPW model accounts for include the probability of wind-driven outages for each grid cell associated with the distribution system plus the probability of tree overstrike risk.

The results of the PSPS Consequence Model establish the level of risk at various levels of granularity including substation level risk to risk associated with individual customers associated with each circuit segment.

5.2.2 Risk and Risk Components Calculation

The electrical corporation must calculate each risk and risk component defined in Section 5.2.1. Additional requirements for these calculations are located in Appendix B "Calculation of Risk and Risk Components." These are the minimum requirements and are intended to establish the baseline evaluation and reporting of all electrical corporations.

If the electrical corporation includes additional risk components in its calculation, it must report each of those components in its WMP in a similar format. The electrical corporation must list all risk model components it identifies as uncertain and disclose if this uncertainty is assessed using probability distributions, expected values, or percentiles. The electrical corporation must describe how probability distributions are stored and how coherence is maintained. For each uncertain component that is not assessed using probability distributions, the electrical corporation must explain why probability distributions are not used and justify its elected assessment method.

The electrical corporation must provide schematics illustrating the calculation of each risk and risk component as necessary to demonstrate the logical flow from input data to outputs, including separate items for any intermediate calculations.

The electrical corporation must summarize any differences between its calculation of these risk components and the requirements of these Guidelines. These differences may include any of the following:

- *Additional input parameters beyond the minimum requirements for a specific risk component;*
- *Calculations of additional outputs beyond the minimum requirements for a specific risk component; and*
- *Calculations of additional risk components defined by the electrical corporation in Section 5.2.1.*

The process used to combine risk components must be summarized for each relevant risk component. This process must align with the requirements in the most recent CPUC decision governing RAMP filings.[26] *If the electrical corporation uses scaling factors (such as Multi-Attribute Value Functions (MAVF) or representative cost), it must present a table with all relevant information needed to understand this procedure (including each scaling factor used, the value of the scaling factor, how it is utilized, an explanation of its purpose, and a justification for the value chosen). The electrical corporation must organize this discussion into the following two subsections focusing on likelihood and consequence.*

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[26] *Pub. Util. Code § 8386(c)(13).*

5.2.2.1 Likelihood of Risk Event

The electrical corporation must discuss how it calculates the likelihood that its equipment (through normal operations or failure) will result in a wildfire and the likelihood of issuing an outage event. The risk components discussed in this section must include at least the following:

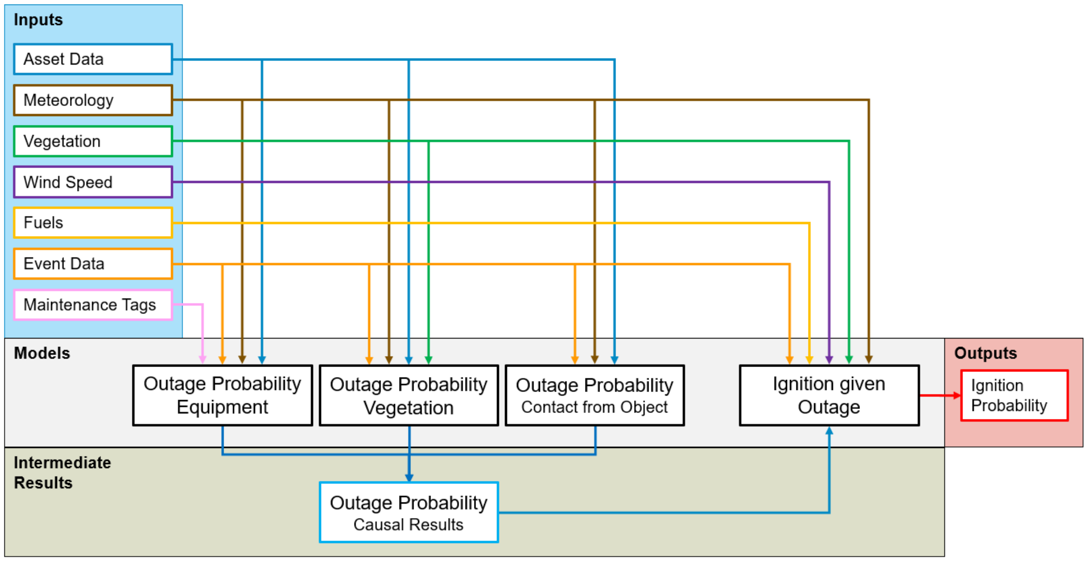
- *Ignition likelihood:*
  - *Equipment caused likelihood of ignition;*
  - *Contact from vegetation likelihood of ignition;*
  - *Contact from object likelihood of ignition;*
- *Burn likelihood;*
- *PSPS likelihood; and*
- *PEDS outage likelihood.*

Ignition Likelihood (Probability of Ignition) for Distribution

The distribution and transmission ignition likelihood calculations use different algorithmic approaches.

The distribution probability of ignition p(i) is the likelihood that an asset-based ignition will occur during a fire season. Probability of ignition is predicted by the Probability of Ignition Given Outage model using the probability of outage predictions from all of the Asset Equipment and Contact from Object models along with other attributes such as environmental conditions. Fire season probability of ignitions is individually predicted for each specific Asset Equipment, Contact from Vegetation, and Contact From Object model. Figure 5-2-1 provides a schematic overview of the distribution probability of ignition calculation

FIGURE-5-2-1:
DISTRIBUTION IGNITION LIKELIHOOD CALCULATION SCHEMATIC



<u>Probability of Ignition Given Outage</u>

The Probability of Ignition Given Outage model, p(i|o), takes as its input the probability of outage, p(o), results from an Asset Equipment or Contact From Object model. The percentage of outages that result in an ignition varies on the outage type. The p(i|o) model uses failure model-specific attributes and environmental conditions to determine the likelihood that a given outage is likely to result in an ignition.

For asset-based event models, the probability of ignition for a given asset is the product of its probability of ignition given an outage and its probability of an outage:

$$p(i)_{asset} = p(i|o)_{asset} * p(o)_{asset}$$

For Contact From Object models, which are location, pixel-based models, the probability of ignition for a given location is the product of the location probability of ignition given outage and the location probability of outage for a specific model:

$$p(i)_{loc} = p(i|o)_{loc} * p(o)_{loc}$$

Individual asset and contact from object probabilities can be composited to determine a summed probability of ignition for an asset or location:

$$p(i)_{loc/asset} = \sum_{loc/asset} p(i|o)_{loc/asset} * p(o)_{loc/asset}$$

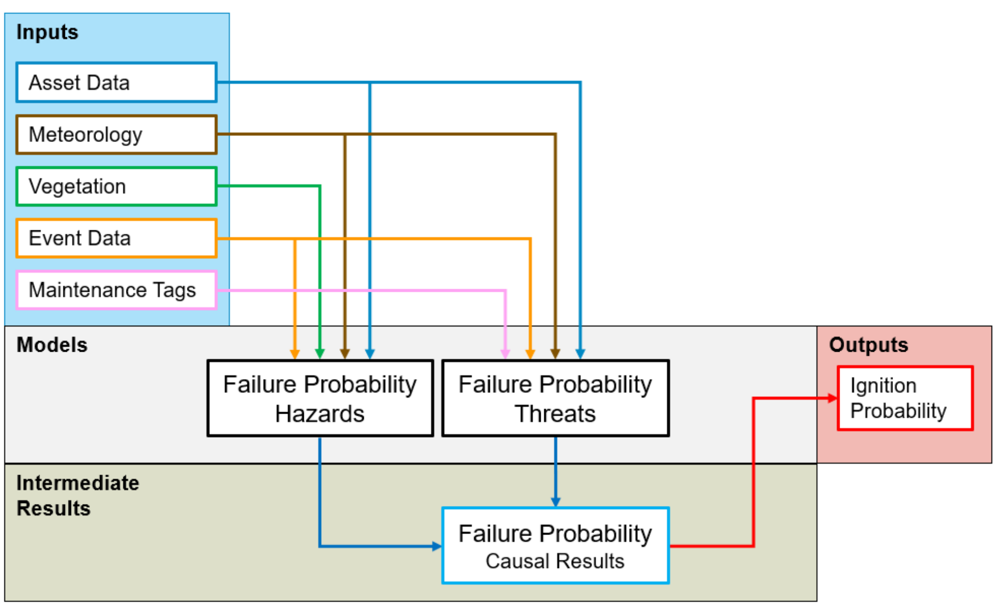
Where:

asset	Modeled asset type: conductor, transformer, support structure, etc.
loc	Asset location expressed as a 100 meter square pixel within the PG&E service territory
p(i)	Probability of Ignition
p(i|o)	Probability of Ignition given an Outage
p(o)	Probability of Outage

Ignition Likelihood (Probability of Ignition) for Transmission

Figure 5-2-2 provides a schematic overview of the transmission probability of ignition calculation.

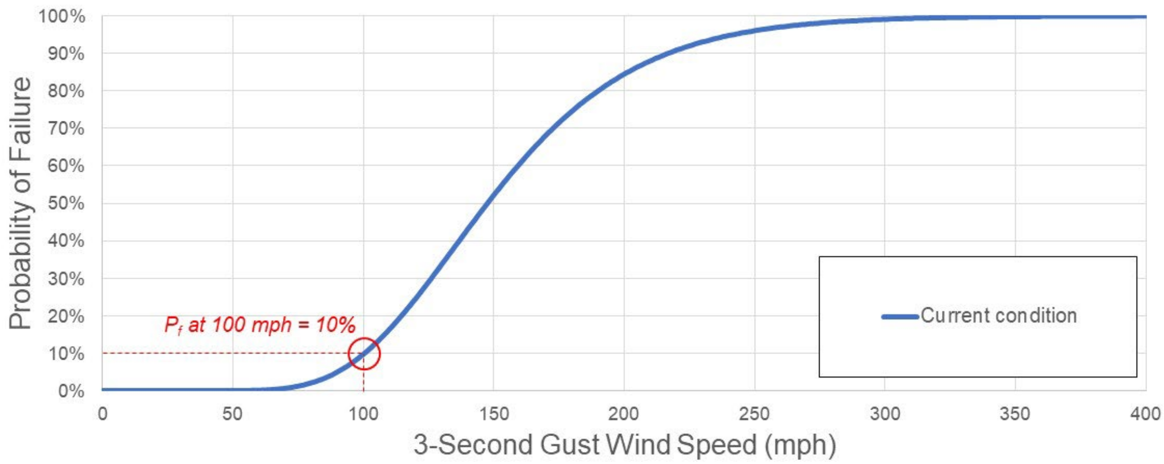
FIGURE 5-2-2:
TRANSMISSION IGNITION LIKELIHOOD CALCULATION SCHEMATIC



The transmission probability of ignition model uses a mix of first principle and machine learning (ML) probability of failure causal models.

First principle causal models are implemented as fragility curves optimized for a specific threat. The underlying first principle relationships set the shape of the fragility curve. Figure PG&E-5.2.2.1-1 presents an example causal fragility curve.

FIGURE PG&E-5.2.2.1-1:
TRANSMISSION PROBABILITY OF FAILURE FRAGILITY CURVE



ML causal models directly estimate probability of failure values in the same manner as the distribution probability models. Also, like distribution, the sums of predicted transmission asset probability of failures are calibrated to match annual historical failure rates. The annualized transmission asset probability of failure serves as a proxy for the probability of ignition. The need for a probability of ignition proxy value is driven by the very low annual number of transmission asset-related ignitions.

The probability of ignition assigned at a transmission support structure location is proxied as the sum of the probability of failures from a composite of the first principle and ML causal model results:

$$p(i)_{ss} = p(f)_{ss} = \sum_{fpm} p(f)_{fpm} + \sum_{ml} p(f)_{ml}$$

Where:

ss	Support Structure
fpm	First-Principle Model for Probability of Failure
ML	Machine Learning model for Probability of Failure
p(f)	Probability of Failure
p(i)	Probability of Ignition

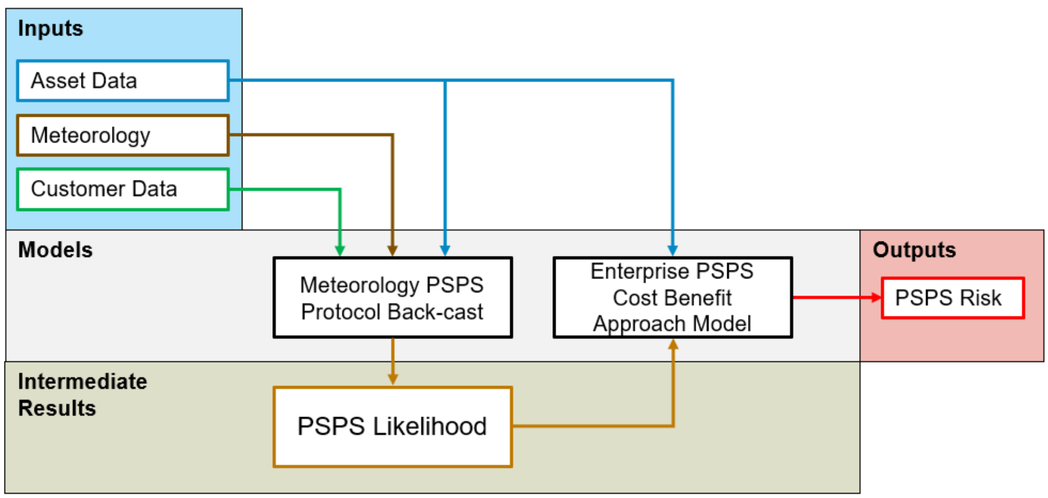
Burn Likelihood

Burn Likelihood is a part of Wildfire Consequence and is discussed in Section 5.2.1 above.

PSPS Likelihood

Figure 5-2-3 provides a schematic overview of the PSPS risk calculation from likelihood and consequence.

FIGURE 5-2-3:
PSPS RISK CALCULATION PROCEDURE SCHEMATIC



The PSPS likelihood is estimated based on a historical PSPS event lookback. For the 2026 WMP and 2027 GRC filing, PG&E will no longer account for Potentially-Impacted Customers (PIC) due to the low incremental risk associated with these customers.[27]

$$Likelihood_{sp\_id} = \frac{\#\ customer\ events}{5\ years} \times \frac{Average\ outage\ duration}{Event}$$

Where:

sp_id	Service Point ID
Event	PSPS Event

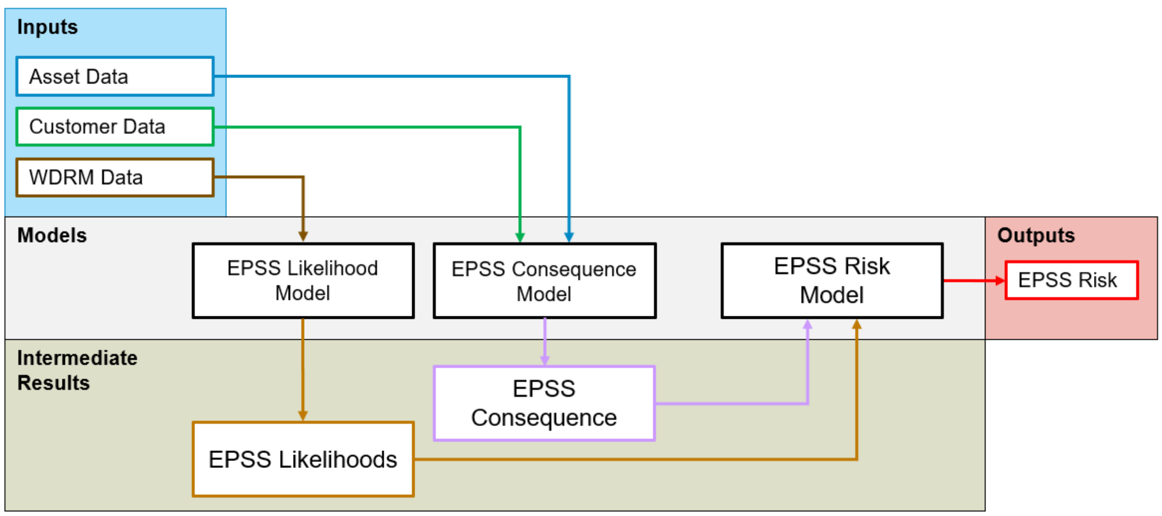
27 Updated based on Substantive Errata filing on April 18, 2025 in accordance with Energy Safety's issuance of Revision Notice at 21.

The PSPS likelihood of events based on the two data inputs is assessed at each individual customer service point based on the circuit configuration, allowing individual annual probabilities for each customer.

EPSS (PEDS) Likelihood

Figure 5-2-4 provides a schematic overview of the EPSS risk calculation from likelihood and consequence.

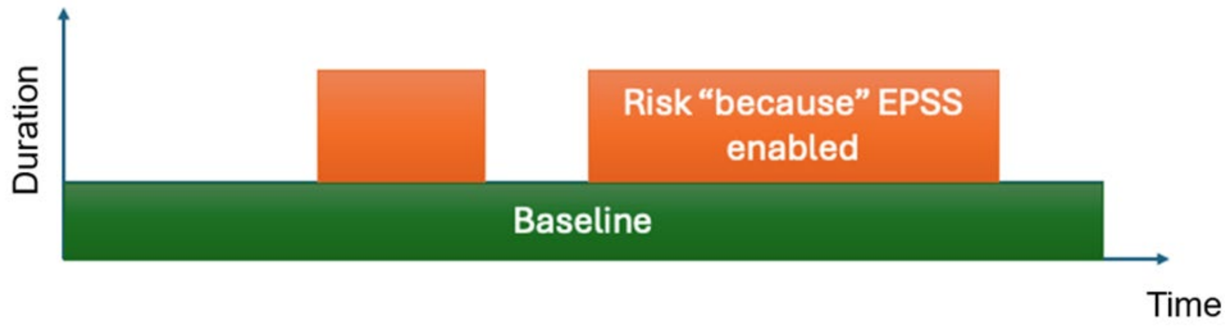
FIGURE-5-2-4:
EPSS RISK CALCULATION PROCEDURE SCHEMATIC



EPSS devices are enabled on powerlines when the risk of wildfire is high. Without EPSS, if a tree branch were to fall on a powerline, the recloser would attempt to re-establish power. When EPSS is enabled, the recloser is limited to attempting to re-establish power for only 60 milliseconds. If it cannot re-establish power within that timeframe, the power will remain off, resulting in fewer wildfires in high-risk areas. EPSS enablement does not increase the number of faults but does increase the number of sustained outages as probable momentary outages can become sustained outages.

The goal of the EPSS outage risk model is to determine the amount of additional risk from EPSS enablement. EPSS outage risk is the outage risk when EPSS is enabled minus the baseline outage risk that exists without EPSS as shown in Figure PG&E-5.2.2.1-2. This model help determine the likelihood of an outage with and without EPSS enabled.

FIGURE PG&E-5.2.2.1-2:
EPSS AND BASELINE OUTAGE RISK



The likelihood of an EPSS-enabled sustained outage on a circuit segment is estimated based on the portion of the wildfire season when EPSS is enabled and the expected number of sustained outages, as calculated from WDRM v4 event probability models. Our EPSS outages dataset reveals that out of approximately 8,000 outages with EPSS enabled, all but a few outages were sustained outages. Therefore, when EPSS is enabled, any fault is assumed to result in a sustained outage.

$$N_{EPSS\_enabledsustainedoutages,\ s,\ cs} = f_{EPSS\_enabled,\ cs} * N_{outages,\ s,\ cs}$$

Where:

cs	circuit segment
s	WDRM event probability model
NEPSS_enabledsustainedoutages,s, cs	number of expected sustained outages per WDRM event probability model when EPSS is enabled for a circuit segment
N outages, s, cs	expected outage count from each WDRM event probability model on a circuit segment
f EPSS_enabled, cs	fraction of wildfire season EPSS is enabled on a circuit segment

The EPSS Outage Risk model also considers the fraction of failures that turn into sustained outages when EPSS is not enabled so that the baseline outage risk can be subtracted from the EPSS enabled risk. To determine this, we factor in the portion of time when EPSS is enabled on a circuit segment, number of expected outages for a WDRM subset on the circuit segment, and the fraction of sustained outages out of the total number of outages. When EPSS is enabled, this same event would result in a sustained outage.

$$N_{sustainedoutages,s,csEPSS\_disabled} = f_{EPSS\_enabledcs} * N_{outages,s,cs} * f_{sustained,s}$$

Where:

cs	circuit segment
s	subset
f EPSS_enabled, cs	fraction of wildfire season when EPSS is enabled for a circuit segment
N outages,s,cs	expected outage count for each subset on circuit segment (provided by WDRM)
Nsustainedoutages,s,csEPSSdisabled	Number of sustained outages for each WDRM subset on circuit segment when EPSS is disabled
f sustained, s	number of sustained outages divided by total number of outages for WDRM subset on a circuit segment

Historically, the fraction of sustained outages out of total outages accounts for roughly 85 percent of outages in HFTD/HFRA.

5.2.2.2 Consequence of Risk Event

The electrical corporation must discuss how it calculates the consequences of a fire originating from its equipment and the consequence of implementing an outage event. The risk components discussed in this section must include at least the following:

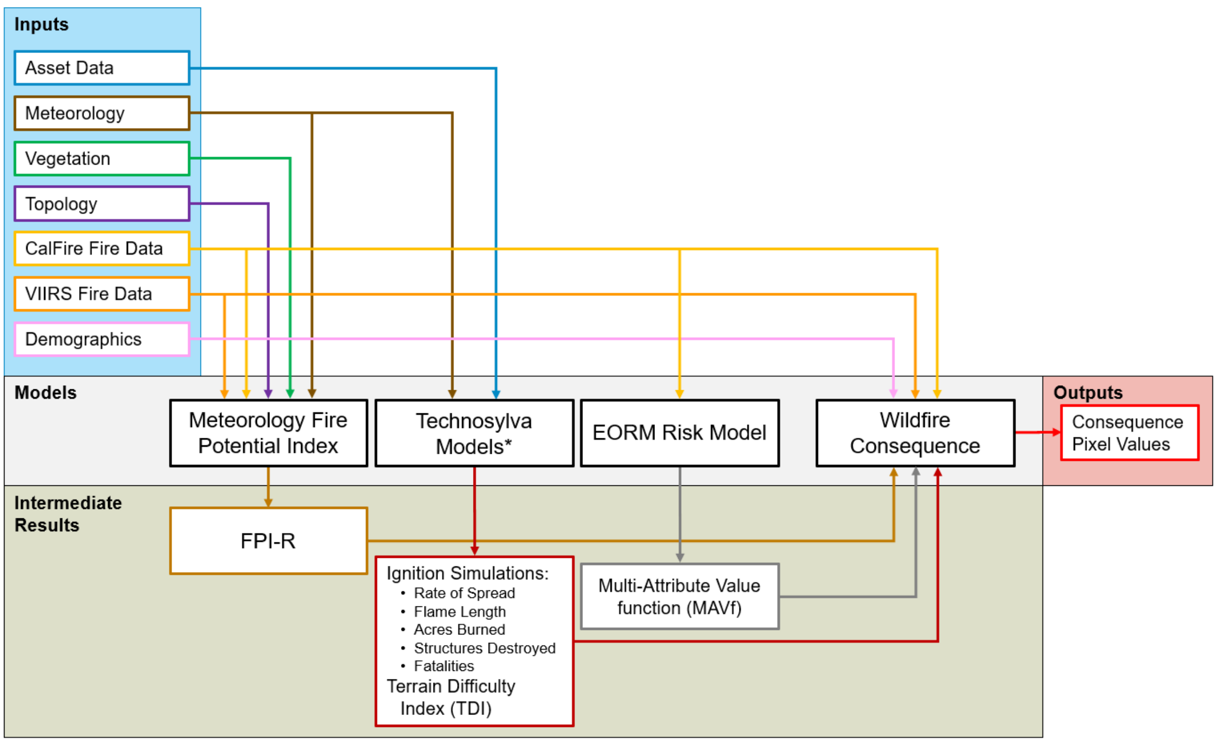
- *Wildfire consequence;*
- *Wildfire hazard intensity;*
- *Wildfire exposure potential;*
- *Wildfire vulnerability;*
- *PSPS consequence;*
- *PSPS exposure potential;*
- *PSPS vulnerability;*
- *PEDS outage consequence;*
- *PEDS outage exposure potential; and*
- *PEDS outage vulnerability.*

In Section 5.2.1 we describe how PG&E calculates CoRE and the data that is used in the calculations. The CoRE calculations described here in Section 5.2.2.2 address WFC, wildfire hazard intensity, and wildfire exposure potential. We discuss PSPS consequence, PSPS exposure potential, and PSPS vulnerability at the end of this section.

Wildfire Consequence

Figure PG&E-5-2-5 provides a schematic overview of the WFC calculation.

FIGURE PG&E-5-2-5:
WFC CALCULATION PROCEDURE SCHEMATIC

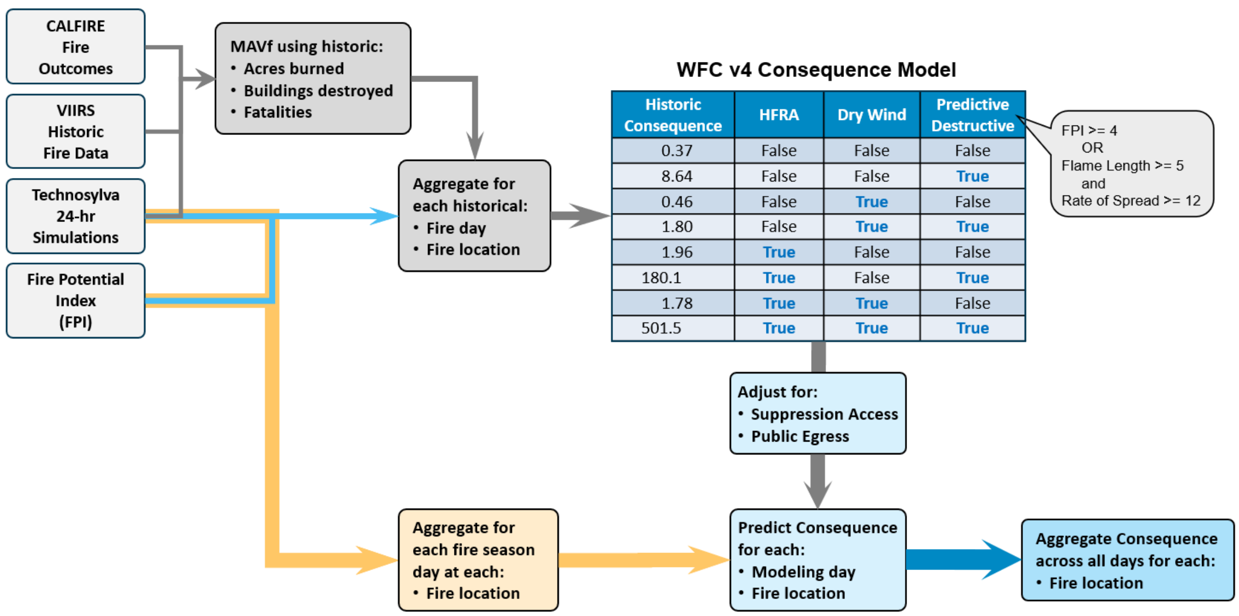


The WFC v4 consequence values are calculated from three components:

- Base Consequence: Considers hazard intensity and exposure potential;
- Wildfire Suppression Impact; and
- Public Egress Impact: Considers vulnerability.

The results of the Base Consequence, Wildfire Suppression Impact, and Public Egress Impact are joined to determine the combined set of model results for acres burned, structures destroyed, and potential fatalities, expressed as a MAVF consequence value. Figure PG&E-5.2.2.2-1 shows the process used for building the base consequence value partition table. The partition table is used to evaluate the annual fire season consequence value for each equipment asset location by aggregating the consequence values for each individual day over several historical fire season. Similar partition tables are used to determine the adjustments for wildfire suppression and public egress impacts.

FIGURE PG&E-5.2.2.2-1:
CONSEQUENCE MODELING PROCESS



PSPS Consequence

PSPS consequence is based on PSPS impact and current PSPS protocols. For each individual event and customer, there is an expected weather period in which a customer is expected to be de-energized. Each PSPS event is expected to have a different weather outage duration. An additional duration is added to account for switching and patrol prior to restoration before and after the PSPS event. The PSPS team estimates that patrol and restoration typically take 11 hours; this estimate is used instead of the Estimated Time of Restoration time. The combination of weather, switching, and restoration is represented as total CMI.

To factor in critical customers, PG&E applies a weighting to the consequence based on the critical customer categorizations shown in Table PG&E-5.2.2.2-2 below. For example, CC1 customers would have higher consequence and priority because these are emergency services such as hospitals, fire, and police stations.

TABLE PG&E-5.2.2.2-2:
CRITICAL CUSTOMER WEIGHTINGS

Customer Type	Customer Weighting	Customer Category
Extreme	100	CC1
Significant	5	Life Support, Medical Baseline & Low Income, Life Support & Low Income
Elevated	2	CC2, CC3, CE1, CE2, CE3, EE, PR1, SC1, SC2, SC3, SE1, SE2, SE3, TE1, TE2, TT1, TT2, Medical Baseline, Self-Identified Vulnerable, Self-Identified Disabled, Low Income
Regular Customer	1	Regular Customer

<u>EPSS Consequence</u>

The consequence of a sustained outage on a circuit segment is estimated CMI times the value of service for the customers on that circuit segment. Typically, when EPSS is enabled, more customers lose power during an outage. This is because a fault will extend upstream to the nearest EPSS-enabled protective device rather than the nearest protective device. PG&E data shows that the duration of an outage is not significantly different whether or not EPSS is enabled. When EPSS is enabled, the CMI is the duration of the outage times the number of customers impacted for the enabled circuit segment. The overall value of service for a circuit segment is the weighted average of the value of service for each customer class (Residential, Small Commercial & Industrial, and Medium Commercial & Industrial) by the number of customers in each class.

$$\mathbf{VOS_{cs} = \sum_{c\in\{RES,\ SMALL\ C\&I,\ MEDIUM\ C\&I\}} VOSc\ * N_{c,cs}\ /N_{cs}}$$

Where:

Ncs	Number of circuit segments
Nc,cs	Number of customers per class on circuit segment
VOSc	Value of service per customer class
VOScs	Value of service on a circuit segment
∑c∈{RES, SMALL C&I, MEDIUM C&I}	Summation of customers across all classes

$$\boldsymbol{C_{EPSS\_enabledsustainedoutages,m,cs} = D_{sustainedoutage,m,cs} * N_{EPSS\_enabledcustomers,m,cs} * VOS_{cs}}$$

Where:

cs	Circuit segment
CEPSS_enabledsustained outages, m, cs	Consequence of EPSS-enabled sustained outages across circuit segment asset types
Dsustained outage, m, cs	Duration of sustained outages across circuit segment asset types
m	Asset type (Integrated Grid Planning (IGP) Model)
NEPSS_enabledcustomers, m,cs	Number of EPSS-enabled customers across asset types on a circuit segment
VOScs	Value of service on a circuit segment

The expected duration of an EPSS-enabled sustained outage on a circuit segment is calculated by taking a weighted average of the sum of all assets (a) of IGP Model asset types and their upstream protective devices on the circuit segment.

Dsustainedoutage,m,cs = 1/Nm,cs ∑ a in cs and of type m Da(mp)

Where:

a	Asset
cs	Circuit segment
Da(m,p)	Duration of asset outage per asset type and protective device
m	Asset type (i.e., conductor, support structure)
Nm,cs	Number of individual assets of type (m) on a circuit segment
p	Protective device (breaker, Dynamic Protection Device (DPD), fuse, switch)
∑ a in cs and of type m	Sum asset outage across all asset types on circuit segment

5.2.2.3 Risk

The electrical corporation must discuss how it calculates each risk, and the resulting overall utility risk defined in Section 5.2.1. The discussion in this section must include at least the following:

- *Overall utility risk;*
- *Wildfire risk;*
- *Outage program risk;*
- *PSPS risk; and*

- *PEDS outage reliability risk.*

Overall Utility Risk

PG&E calculates overall utility risk as the sum of Ignition (Wildfire) Risk + PSPS risk + EPSS risk.

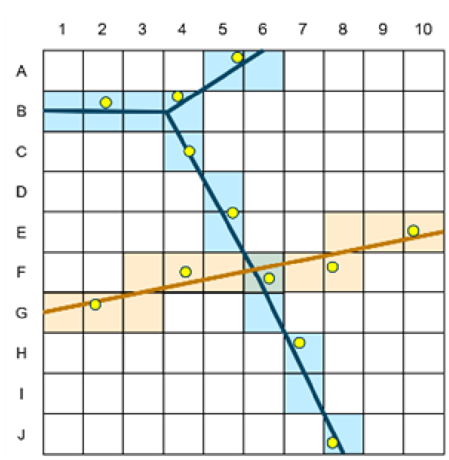
Ignition (Wildfire) Risk

Ignition Risk (WDRM v4) for distribution is determined for equipment asset locations for each risk driver causal model LoRE, p(i), and CoRE, WFC. The WDRM is supported by risk driver models that produce both equipment asset and geospatial results. Equipment asset models produce results that estimate event probabilities or risk for individual assets at point locations. Spatial, or grid pixel, models, product results that estimate event probabilities or risk for contact from vegetation and contact from object within 100 meter by 100 meter square pixels that form a grid over the distribution and transmission service territories. The WFC model also produces geospatial results assigned to the same 100 meter by 100 meter pixel grid. The individual risk driver ignition risk results need to be aggregated to circuit segments using composite risk drivers that are meaningful to the corresponding mitigation programs.

Aggregation Methodology

Circuit segment aggregation sums up all the potential risk that was modeled along the length of a segment. Figure PG&E-5.2.2.3-1 shows an example of two circuit segments that intersect multiple grid pixels and have multiple assigned equipment assets (○). For geospatial models, this pixel risk for any pixel that is intersected by a circuit segment is summed to determine the aggregated pixel risk. For asset models, the risk for each asset belonging to the circuit segment is summed to determine the aggregated asset risk. Finally, the summed pixel and asset risks can in turn be summed to calculate the total aggregated circuit segment risk.

FIGURE PG&E-5.2.2.3-1:
CIRCUIT SEGMENT AGGREGATION



Shared pixels and assets complicate circuit segment aggregation of risk. In Figure PG&E-5.2.2.3-1 the two circuit segments share a common pixel, F6, and a support structure (pole) asset also located in pixel F6. To keep the total sum of risk on the network constant, these shared risk results must be partially distributed to each of the circuit segments. The aggregation methodology, in this case, would assign half of the F6 pixel risk and half of the support structure risk to each of the circuit segments.

Compositing Event Models

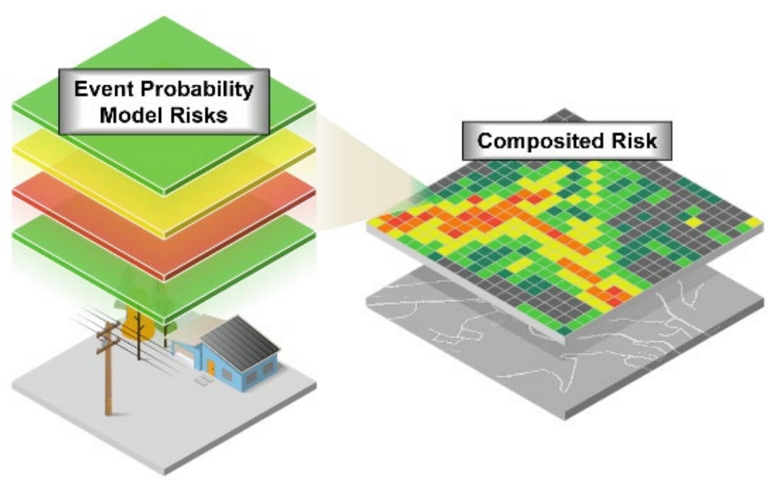
Ultimately, the purpose of ignition risk modeling (WDRM) is to inform the prioritization of wildfire risk mitigation programs. The WDRM risk driver causal model risk results can be flexibly composited to provide risk values and priority rankings for specific mitigation programs. Using composited results, programs can prioritize mitigation of the highest risks while using the contributing event probability models to understand the best mediation approach to handle the specific components of risk.

Risk can be composited for any combination of event probability models. Mitigation planners and Subject Matter Experts (SME) can focus on the drivers of risk for which they are responsible with confidence that their composited view is relevant to their work planning needs.

Compositing Methodology

An event probability model produces, by asset or pixel, a probability of ignition. Combining a probability of ignition with its consequence produces the wildfire risk. Probability of ignition and risk results can be composited to create total probability of ignition and total risk. As visualized in Figure PG&E-5.2.2.3-2, individual model results are summed to determine total composite results.

FIGURE PG&E-5.2.2.3-2:
MODEL COMPOSITING



Mitigation Composites

Mitigation program work planners are often interested in a partial set of event probability model risk results. Custom composites are configured so that the total risk for only the applicable event models are considered as part of the work prioritization process. Figure PG&E-5.2.2.3-3 illustrates how model selection can be used to configure a composite for a specific work plan.

FIGURE PG&E-5.2.2.3-3:
MITIGATION COMPOSITE MEMBERSHIP

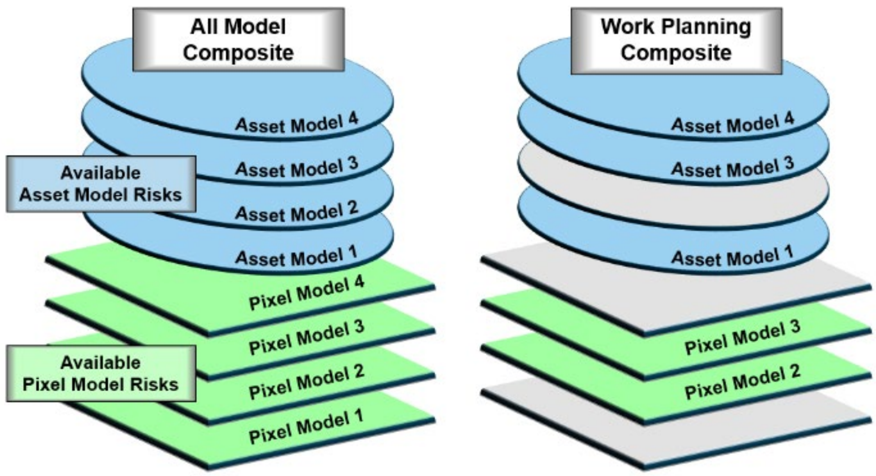


Table PG&E-5.2.2.3-1 WDRM v4 delivers the following mitigation composites, composed from the 23 available event probability models:

TABLE PG&E-5.2.2.3-1:
WDRM V4 MITIGATION COMPOSITES

Event Probability Model	All Composite	System Hardening	Vegetation Management
Animal – Bird	✓	✓	×
Animal – Squirrel	✓	✓	×
Animal – Other	✓	✓	×
Capacitor Bank	✓	✓	×
Dynamic Protection Device (DPD)	✓	✓	×
Fuse	✓	✓	×
Primary Conductor – Line Slap	✓	✓	×
Primary Conductor – Wire Down	✓	✓	×
Primary Conductor – Other	✓	✓	×
Secondary Conductor	✓	✓	×
Support Structure – Electrical	✓	×	×
Support Structure – Equipment	✓	✓	×
Switch	✓	✓	×
Third Party – Balloon	✓	✓	×
Third Party – Vehicle	✓	✓	×
Third Party – Other	✓	✓	×
Transformer – Failure	✓	✓	×
Transformer – Leaking	✓	×	×
Vegetation – Branch	✓	✓	✓
Vegetation – Trunk	✓	✓	✓
Vegetation – Other	✓	✓	✓
Voltage Regulator	✓	✓	×
Other Equipment	✓	✓	×

Outage Program Risk

Outage program risk is the sum of PSPS risk and EPSS (PEDS) risk.

PSPS Risk

PG&E calculates PSPS risk at the segment circuit level. As described in previous sections, PSPS likelihood and PSPS consequence are calculated by the probability and consequence of each individual customer service_point_ID (SPID). Those calculations provide the PSPS risk score per customer. The risk score represents annual dollarized reliability risk related to PSPS events, accounting for frequency of events, duration and customer impacts.

The customer risk score is then applied to a critical customer weighting that is based on their customer classification. Lastly, all customer risk scores are aggregated to determine the overall PSPS risk score.

The following formulas display how to calculate the PSPS risk, likelihood and consequence at the segment circuit level:

$$Risk_{CS} = \sum Risk_{sp\_id}$$

$$Likelihood_{CS} = \sum Likelihood_{sp\_id}$$

$$Consequence_{CS} = \frac{Risk_{CS}}{Likelihood_{CS}}$$

Consequence uses a likelihood-weighted consequence, and the likelihood is summed up across SPIDs. The total PSPS risk is then divided by the total likelihood to derive the consequence for that circuit segment.

The results of the PSPS Consequence Model are then calibrated to PG&E's Enterprise Risk Model's CBA risk score for PSPS.

EPSS Outage Risk

The goal of the EPSS outage risk model is to determine the amount of additional risk incurred when EPSS is enabled. Therefore, EPSS outage risk is the outage risk when EPSS is enabled minus the baseline outage risk that exists without EPSS. As a result, we need to determine the risk of an outage with and without EPSS enabled.

$$\mathbf{epss\_risk_{cs} = risk\_with\_epss\_enabled_{cs} - risk\_with\_epss\_disabled_{cs}}$$

$$risk\_with\_epss\_enabled_{cs} = \sum_{m \in asset\_types} N^{EPSS\_enabled}_{sustained\ outages,m(s),cs} * C^{EPSS\_enabled}_{sustained\ outages,m,cs}$$

Where:

cs	circuit segment
m	asset type
s	subset (WDRM)
$C_{EPSS\_enabled sustained\ outages,\ m,\ cs}$	consequence of EPSS-enabled sustained outages for each IGP asset type on circuit segment (conductor, support structure)
$\mathbf{N_{EPSS\_enabled sustained\ outages,\ m(s),cs}}$	Number of expected sustained outages when EPSS is enabled for WDRM subset mapped to IGP Model asset type (conductor, support structure)
$\sum_{m \in asset\_types}$	Sum across all IGP asset types (conductor, support structure)

5.2.3 Key Assumptions and Limitations

Since the individual elements of risk assessment are interdependent, the interfaces between the various risk models and activities must be internally-consistent. In this section of the WMP, the electrical corporation must discuss key assumptions, limitations, and data standards for the individual elements of its risk assessment.[28] *This must include the following:*

- *Key modeling assumptions made specific to each model to represent the physical world and to simplify calculations;*
- *Data standards, which must be consistently defined (e.g., weather model predictions at a 30-foot (ft.) [10-meter] height must be converted to the correct height for fire behavior predictions, such as mid-flame wind speeds);*
- *Consistency of assumptions and limitations in each interconnected model, which must be traced from start to finish, with any discrepancies between models discussed;*
- *Stability of assumptions in the program, including historical and projected changes; and*
- *Monetization of attributes, if utilized, including (if applicable) the selected value of statistical life, dollar value of injury prevention, and dollar value of reliability risk.*

More developed activities (programs) regularly monitor and evaluate the scope and validity of modeling assumptions. Monitoring and evaluation categories may include:

- *Adaptation of weather history to current and forecasted climate conditions;*

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28 *Pub. Util. Code § 8386(c)(4).*

- *Availability of suppression resources including type, number of resources, and ease of access to incident location;*
- *Height of wind driving fire spread including any wind adjustment factor calculations;*
- *General equipment failure rates based on historical trends for equipment type, equipment age, overdue maintenance, and any wind speed functional dependences;*
- *General vegetation contact rates based on historical trends for vegetation species, vegetation height, and environmental factors such as wind speed functional dependences;*
- *Height of electrical equipment in the service territory;*
- *Stability of the atmosphere and resulting calculation of near-surface winds;*
- *Vegetative fuels including models that account for fuel management activities by other land managers (e.g., thinning, prescribed burns);*
- *Combination of risk components and weighting of attributes and resulting impacts;*
- *Wind load capacity for electrical equipment in the service territory;*
- *Number, extent, and type of community assets at risk in the service territory;*
- *Proxies for estimating impact on customers and communities in the service territory; and*
- *Extent, distribution, and characteristics of vulnerable populations in the service territory.*

The electrical corporation must document each assumption in Table 5-1. The electrical corporation must summarize assumptions made within models in accordance with the model documentation requirements in Appendix B.

Table 5-1 below shows our risk modeling assumptions and limitations.

TABLE 5-1:
RISK MODELING ASSUMPTIONS AND LIMITATIONS

Assumption	Rationale/Justification	Limitation	Applicable Model
It is assumed that events from June-November, the typical timing of fire seasons, are representative of all events capable of producing wildfire risk	If the training data for the WDRM included events caused by winter storms, icing, and other causal processes not compatible with ignition and wildfire spread, the pattern of model predictions would be influenced by events that contribute little or no wildfire risk. To avoid exposing the model to misleading data, the training events are restricted to June through November.	We assume that wildfires are possible outside of the typical fire season and that ignitions and wildfires occurring outside of the typical fire season would have the same relationship with the model covariates as the ones the model is already trained on.	Overall Utility Risk Ignition/Wildfire Risk (WDRM/WTRM) Ignition Likelihood Ignition/WFC Equipment Likelihood of Ignition Contact from Object Likelihood of Ignition
The WDRM v4 is an “observational model” that uses the pattern of past outages and ignitions to predict their future.	The core assumption of such an approach is that the correlations and causal processes that have governed past outages and ignitions will continue to govern them in the future.	N/A	WDRM Ignition Likelihood Equipment Likelihood of Ignition Contact from Object Likelihood of Ignition

TABLE 5-1:
RISK MODELING ASSUMPTIONS AND LIMITATIONS
(CONTINUED)

Assumption	Rationale/Justification	Limitation	Applicable Model
ML tools, like feature generation, model regularization, and the preferential use of out of sample performance metrics, are well suited to the prediction of ignition probability and risk.	The key features of the ML tools are the primary output of the WDRM v4.	N/A	Ignition/Wildfire Risk (WDRM) Ignition Likelihood Equipment Likelihood of Ignition Contact from Object Likelihood of Ignition
WTRM builds on assumptions used by the Transmission Operational Assessment (OA) Model. PG&E identified 47 components through a Failure Modes and Effects Analysis which could result in a wildfire ignition if they failed. These 47 components were divided into 9 asset groups and asset specific datasets are assigned to each one.	While the scope of the WTRM exceeds that of the OA Model in terms of incorporating other hazards, the asset group types remain a proxy for a collection of components that share similar: (1) life cycles, (2) sensitivities to threats and hazards, and (3) Asset Management strategies.	N/A	Ignition/Wildfire Risk (WTRM v2)
Where age data is unavailable from system of records, a logic is used to determine the most conservative age of the asset.	Age data is required for each component for the WTRM to compute an annual failure rate.	Some equipment risk could potentially be overestimated due to equipment using assumed age.	Ignition/Wildfire Risk (WTRM v2)

TABLE 5-1:
RISK MODELING ASSUMPTIONS AND LIMITATIONS
(CONTINUED)

Assumption	Rationale/Justification	Limitation	Applicable Model
Circuits operating outside their rated capacity or in abnormal configuration do not have an increased ignition risk.	In July 2024 during an intense heat event, PG&E saw a significant uptick in fire risk exposure and associated ignition events. PG&E did an analysis that found that conductors and connectors under high heat stress, both external (due to extended heat) and internal (due to load) could be one of the contributing factors.	While the distribution (WDRM v4) probability of failure model does include the risk for abnormal circuits, it does not currently identify circuits that are operating within the rated capacity and circuits that are operating outside their rated capacity or circuits in abnormal configuration. PG&E is currently investigating if there is a correlation between circuit condition and higher outage and ignition events. PG&E is collecting data to determine the degree of risk introduced by circuit configuration in the HFTD/HFRA.	WDRM v4
Critical Customer Weightings are based on high level SME judgement.	The assignment of a critical weighting factor to our customers is a subjective process that will continually be reviewed and potentially updated. There has been limited industry research and therefore no industry standard on how different customers are impacted by PSPS events or loss of power. PG&E will continue to work with the industry and Investor-Owned Utility (IOU) partners to better reflect customer risks in our PSPS consequence model. The current weighting system was developed internally to provide a simple differentiation of customer category types.	The distribution of customer risk (and PSPS risk reduction) is partly driven by the type of customers and their critical weighting score. Significant changes to the critical customer weighting could potentially impact Circuit Protection Zone risk ranking and prioritization initiatives	PSPS Risk PSPS Consequence PSPS Likelihood Vulnerability of Community to PSPS

TABLE 5-1:
RISK MODELING ASSUMPTIONS AND LIMITATIONS
(CONTINUED)

Assumption	Rationale/Justification	Limitation	Applicable Model
PSPS safety consequence is based off 50 percent PG&E PSPS planned and 50 percent unplanned long duration outages across the United States (U.S.) Safety accounts for 50 percent of our MAVF PSPS Risk. PSPS events are relatively new and there is minimal SIF data to include in the risk analysis. For this reason, other large external national events (i.e., 2003 NE Blackout, 2011 SW Blackout, 2012 Superstorm Sandy, etc.) were considered in evaluating safety risks associated with PSPS events.	PSPS represented as a non-zero safety risk is reasonable. However, PG&E providing advanced notification for a planned de-energization reduces the safety impact of the outage and should not be treated as an unplanned outage. Given that historical records show no safety impacts, PG&E included unplanned long duration outages across the U.S. (i.e., 2033 NE Blackout, 2011 SW Blackout, 2012 Superstorm Sandy, etc.) at 50 percent, respectively.	The safety consequence of PSPS should not include unplanned outages as it does not accurately represent PSPS itself.	PSPS Risk PSPS Consequence PSPS Likelihood Vulnerability of Community to PSPS
EPSS Consequence assumes that the duration will be the same for outages that occur both with and without EPSS enabled.	Analysis of outages supports the expectation that the duration of an outage will be the same whether or not EPSS is enabled.	As future operational EPSS data becomes available, analysis may discover differences in duration for EPSS enabled outages	EPSS Risk EPSS Consequence
EPSS Likelihood of a fault is independent of whether or not EPSS is enabled.	No known causal mechanism that would cause the fault rate to change when EPSS is enabled.	As future operational EPSS data become available a causal mechanism may be discovered.	EPSS Risk EPSS Likelihood
EPSS Value of Service (VOS) is specific to customer class based on the outputs of the interruption cost estimation calculator	Interruption cost estimation calculator inputs are based on PG&E customer characteristics and historic SAIFI, SAIDI, CAIDI metrics	VOS is based on 2016 data, escalated to 2024 values	EPSS Risk EPSS Consequence
Baseline Risk in the Enterprise Wildfire Risk Model is calibrated to historical performance.	Baseline wildfire risk needs to be calibrated against all other risks within the Company. As such, historical years' performance is used to calculate risk score	Changes in wildfire risk has been dynamic. Baseline risk scores based on historical performance may not be reflective of current performance.	Enterprise Risk Model [(b)]
The FPI and IPW models are observational models that learn the pattern of historical fires, outages, and ignitions together with the conditions under which they occurred to predict future fires, outages, and ignitions.	The rationale of such an approach is that the correlations and causal processes that drive historical fires, outages and ignitions will continue to drive them in the future.	Fires, ignitions and outages of the future may be driven by processes that have not been accounted for in the models.	FPI/IPW[(c)]

TABLE 5-1:
RISK MODELING ASSUMPTIONS AND LIMITATIONS
(CONTINUED)

Assumption	Rationale/Justification	Limitation	Applicable Model
The FPI and IPW models are driven predominantly by weather model forecasts.	Weather is an important driver of fires, outages, and ignitions.	Weather model forecasts, while skillful and well validated, are not a perfect representation of the future state of the atmosphere.	FPI/IPW[(c)]
ML methods, such as feature creation, classification and regression, model sampling, and use of the out of sample performance metrics, are well suited to the prediction of fire, outage, and ignition probability and risk.	The rationale of ML is that it allows the skillful explanation of future fires, outages, and ignitions by using large amounts of data and sophisticated algorithms.	ML models are limited by the amount of data available and the sophistication of the current state-of-the-art algorithms.	FPI/IPW[(c)]

Notes:

- Updated based on Substantive Errata filing on April 18, 2025 in accordance with Energy Safety's issuance of Revision Notice at 21.
- The Enterprise Risk Model is used to calibrate all the wildfire, PSPS, and EPSS risk models listed in Table 5-4 above for the purpose of calculating overall utility risk.
- The FPI/IPW models are operational models and, therefore, do not appear in Table 5-4 below.

5.3 Risk Scenarios

In this section of the WMP, the electrical corporation must provide a high-level overview of the scenarios to be used in its risk analysis in Section 5.2. These must include at least the following:

- *Design basis scenarios that will inform the electrical corporation's long-term wildfire activities and planning; and*
- *Extreme-event scenarios that may inform the electrical corporation's decisions to provide added safety margin and robustness.*

The risk scenarios described in Sections 5.3.1 and 5.3.2 below are the minimum scenarios the electrical corporation must assess in its wildfire risk and outage program risk analysis. The electrical corporation must also describe and justify any additional scenarios it evaluates.

Each scenario must consider:

- *Local Relevance: Heterogeneous conditions (e.g., assets, equipment, topography, vegetation, weather) that vary over the landscape of the electrical corporation's service territory at a level sufficiently granular to permit understanding of the risk at a specific location or for a specific circuit segment. For example, statistical wind loads must be calculated based on wind gusts considering the impact of nearby topographic and environmental features, such as hills, canyons, and valleys; and*
- *Statistical Relevance: Percentiles used in risk scenario selection must consider the statistical history of occurrence and must be designed to describe a reasonable return interval/probability of occurrence. For example, designing to a wind load with a 10,000-year return interval may not be desirable as most conductors in the service territory would be expected to fail (i.e., the scenario does not help discern which areas are at elevated risk).*

5.3.1 Design Basis Scenarios

Fundamental to any risk assessment is the selection of one or more relevant design basis scenarios (design scenarios) that inform long-term activities and planning. In this section, the electrical corporation must identify the design scenarios it has prioritized from a comprehensive set of possible scenarios. The design scenarios identified must be based on the unique wildfire risk and reliability risk characteristics of the electrical corporation's service territory and achieve the primary goal and stated plan objectives of its WMP. The design scenarios must represent statistically relevant weather and vegetative conditions throughout the service territory. The following design scenarios, comprised of various design conditions, are provided for reference and may be used by the electrical corporation to categorize the unique design scenarios employed in its risk analysis.

For wind loading on electrical equipment, the electrical corporation must evaluate statistically relevant design conditions. Statistically relevant wind loads may be calculated based on locally relevant 3-second wind gusts over a 30-year wind speed history during fire season in its service territory. Four wind loading conditions that electrical corporations may consider in developing its design scenarios are:

- *Wind Load Condition 1: Baseline: The baseline wind load condition the electrical corporation uses in design, construction, and maintenance relative to General Order 95, Rule 31.1;*
- *Wind Load Condition 2: Very High: 95th-percentile wind gusts based on maximum daily values over the 30-year history. This corresponds to a probability of exceedance of 5 percent on an annual basis (i.e., 20-year return interval) and is intended to capture annual high winds observed in the region (e.g., Santa Ana winds);*
- *Wind Load Condition 3: Extreme: Wind gusts with a probability of exceedance of 5 percent over the 3-year WMP cycle (i.e., 60-year return interval); and*
- *Wind Load Condition 4: Credible Worst Case: Wind gusts with a probability of exceedance of 1 percent over the 3-year WMP cycle (i.e., 300-year return interval).*

The electrical corporation must describe which wind load design condition(s) it uses for its modeling purposes, and how each condition is evaluated for use in risk modeling. The four conditions above are provided for reference. An alternative approach to statistical wind loads may be used if supported by engineering analysis. If the electrical corporation utilizes a design condition not listed above, it must describe what that condition is (including the timeframe for historical data used), the return interval evaluated, and how the electrical corporation determined to use that condition for risk modeling. For any condition used, the electrical corporation must describe how it is using discrete historical data to determine extremes that may not have been captured within the data when evaluating various return intervals.

The data and/or models the electrical corporation uses to establish locally relevant wind gusts for these design conditions must be documented in accordance with the weather analysis requirements described in Appendix B.

<u>For weather conditions used in calculating fire behavior</u>, the electrical corporation must evaluate probabilistic fire spread scenarios based on statistically relevant history of fire weather. This approach must consider a range of wind speeds, directions, and fuel moistures that are representative of historic conditions. In addition, the electrical corporation must discuss how this weather history is adapted to align with current and forecasted climate conditions. At a minimum, the electrical corporation must consider the following two conditions:

- *<u>Weather Condition 1: Anticipated Conditions</u>: The statistical weather analysis is limited to fire seasons expected to be the most relevant to the next three years of the WMP cycle; and*
- *<u>Weather Condition 2: Long-Term Conditions</u>: The statistical weather analysis is representative of fire seasons covering the historical record and adapted to forecasted climate conditions.*

One possible approach to the statistical weather analysis for fire behavior is Monte-Carlo simulation of synthetic fire seasons in accordance with approaches presented by the USFS.[29,30] However, the electrical corporation must justify the selection of locally relevant data for use in this approach (i.e., Remote Automated Weather Systems data or historic weather reanalysis must be locally relevant).

The electrical corporation must state how it defines "fire weather" and "fire season" for the calculations of these probabilistic scenarios. If the electrical corporation utilizes a design condition not listed above, it must describe what that condition is, including the timeframe for historical data used, and how the electrical corporation determined using that condition. The data and/or models the electrical corporation uses to establish locally relevant weather data for these designs must be documented in accordance with the weather analysis requirements described in Appendix B.

<u>For vegetative conditions not including short-term moisture content</u>, the electrical corporation must evaluate the current and forecasted vegetative type and coverage. Three suggested vegetation conditions to consider include:

- *<u>Vegetation Condition 1: Existing Fuel Load</u>: The wildfire hazard evaluated with the existing fuel load within the service territory, including existing burn scars and fuel treatments that reduce the near-term fire hazard;*
- *<u>Vegetation Condition 2: Short-Term Forecasted Fuel Load</u>: The wildfire hazard evaluated considering the changes in expected fuel load over the 3-year WMP cycle <u>including</u> regrowth of previously burned and treated areas; and*

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29 *M. A. Finney, I. C. Grenfell, C. W. McHugh, R. C. Seli, D. Trethewey, R. D. Stratton, and S. Brittain, 2011, "A Method for Ensemble Wildland Fire Simulation," Environmental Modeling & Assessment 16(2):153–167.*

30 *M. A. Finney, C. W. McHugh, I. C. Grenfell, K. L. Riley, and K. C. Short, 2011, "A Simulation of Probabilistic Wildfire Risk Components for the Continental United States," Stochastic Environmental Research and Risk Assessment 25:973–1000.*

- *<u>Vegetation Condition 3: Long-Term Extreme Fuel Load</u>: The wildfire hazard evaluated considering the long-term potential changes in fuels throughout the service territory. This includes regrowth of previously burned and treated areas and changes in predominant fuel types.*

The electrical corporation must describe which vegetation condition(s) it uses for its modeling purposes, and how the electrical corporation evaluated each condition for use in risk modeling If the electrical corporation chooses a design condition not listed above, it must describe what that condition is, including the timeframe for historical data used, and how the electrical corporation determined the condition(s).

The data and/or models the electrical corporation uses to establish locally relevant fuel loads for these designs must be documented in accordance with the vegetation requirements described in Appendix B.

The electrical corporation must provide a brief narrative on the design scenarios used in its risk analysis. In addition, the electrical corporation must provide a table summarizing the following information:

- *<u>Scenario ID</u>: Identification of each design basis scenario included within its risk modeling (e.g., Scenario 1, Scenario 2);*

- *<u>Design Scenario</u>: The components of each scenario used, as described above or by the electrical corporation (e.g., Weather Condition 1, Vegetation Condition 1); and*

- *<u>Purpose</u>: How the output of the scenario is used within risk modeling if applicable*

The selection, preparation, and use of data, including those representing wind, weather, and vegetation, within the Risk Model Framework and Methodology are designed to produce the most predictive probability (LoRE) models and representative consequence (CoRE) models. The framework presented by Energy Safety in the WMP guidelines presents a different paradigm for the risk modeling that could be conducted for a range of potential future scenarios. PG&E’s risk modeling framework accounts for all scenarios in a single predictive model that is represented by the historical data sets used in model development. As a result, some conditions considered by the extreme scenarios outlined by Energy Safety may not be represented in the historical data.

In all scenarios fire season and fire weather are applied from the following definitions:

- <u>Fire Season</u>: May to November of each calendar year. This generally aligns with California Department of Forestry and Fire Protection’s (CAL FIRE) definition and the historical trend of wildfire activities.

- <u>Fire Weather</u>: Is best represented as the fire danger ratings produced by the FPI. Please see Section 10.6.1 for a detailed description of the FPI model.

Table 5-2 below includes high-level summaries of the data for each of the prescribed scenarios: Weather, Wind, and Vegetation.

Weather

For operational models (FPI, IPWs, OA, PSPS), current weather conditions are used alongside a 30-year meteorology data set. These data sets best align with: Weather Condition 1 – Anticipated Conditions; and Weather Condition 2 – Long-term Conditions. For planning models (WDRM, WTRM, WFC), the 30-year meteorology and worst weather days used in developing the WFC model best align with the Weather Condition 2 – Long-term Conditions.

Wind

For operational models (FPI, IPW, OA, PSPS), current weather conditions are used along with the 30-year meteorology. These data sets best align with: Wind Load conditions 1 – Baseline; and 2 – Very High. For planning models (WDRM, WTRM, WFC), data representing the spatial patterns for historical wind used in the WDRM and WFC best align with: Wind Load conditions 1 – Baseline; and 2 – Very High. For the WTRM, the use of fragility curves (as described in Figure PG&E-5.2.2.1-1) allows the model to estimate structural performance through a wide range of potential wind speeds that could be interpreted to those beyond a 1 in 30-year occurrence such as those outlined in: Wind Load conditions 3 – Extreme; and 4 – Conditional Worst Case.

Vegetation

For operational models (FPI, IPW, OA, PSPS), current fuels are monitored and updated in the model data sets through the current year fire season. This includes the fuel conditions for the locations of recent fire scars and controlled burns. This aligns most closely with Vegetation Condition 1 – Existing Fuels. For WFC, a set of worst weather days during historical fire seasons is used to develop fire simulations of potential ignitions given current fuel conditions.

For planning models (WDRM, WTRM, WFC), a 2030 fuel layer is used within the WFC Model to represent anticipated conditions including the regrowth of current historical fire burn scars. This data most aligns with Vegetation Condition 3 –Long-term Extreme Fuel Load.

TABLE-5-2:
SUMMARY OF DESIGN SCENARIOS

Scenario ID	Design Scenario	Purpose
OP1	Weather 1 Weather 2 Wind Load 1 Wind Load 2 Vegetation 1	Operational models (FPI, IPW)
OP2	Wind Load 1 Wind Load 2 Wind Load 3 Wind Load 4 Weather 1 Weather 2 Vegetation 1	OA Operational Model
PL1	Weather 2 Wind Load 1 Wind Load 2 Vegetation 3	WDRM Planning Model
PL2	Weather 2 Wind Load 1 Wind Load 2 Wind Load 3 Wind Load 4 Vegetation 3	WTRM Planning Model

5.3.2 Extreme-Event/High Uncertainty Scenarios

In this section, the electrical corporation must identify extreme-event/high-uncertainty scenarios that it considers in its risk analysis. These generally include the following types of scenarios:

- *Longer-term scenarios with higher uncertainty (e.g., climate change impacts, population migrations, extended drought);*
- *Multi-hazard scenarios (e.g., ignition from another source during a PSPS); and*
- *High-consequence, but low-likelihood ("Black Swan") events (e.g., acts of terrorism, 10,000-year weather).*

While the primary risk analysis is intended to be based on the design scenarios discussed in Section 5.3.1, the potential for high consequences from extreme events may provide additional insight into the mitigation prioritization described in Section 6.

The electrical corporation must provide a brief narrative on the extreme-event scenarios used in its risk analysis. The electrical corporation must describe these scenarios, their purpose in the analysis, and identify the modeling method used (e.g., power law distribution). In addition, the electrical corporation must provide a table summarizing the following information:

- *Identification of each extreme-event risk scenario (e.g., Scenario 1, Scenario 2);*
- *Components of each scenario (e.g., Weather Condition 1, Vegetation Condition 1); and*
- *Purpose of the scenario.*

Table 5-3 provides an example of the minimum acceptable level of information.

TABLE 5-3:
EXAMPLE OF SUMMARY OF EXTREME EVENT SCENARIOS

Scenario ID	***Extreme-Event Scenario***	***Purpose***
ES1	*Climate Change 1* *Weather Condition 2* *Vegetation Condition 3*	*Impact of climate change on long-term fire behavior calculation*

PG&E is not completing Table 5-3 above as we do not directly account for extreme event scenarios as articulated in the WMP Guidelines in risk modeling. PG&E's Company Emergency Response Plan (CERP)[31] includes a plan to address an event where an extreme scenario wildfire risk is realized coincident with other risk events. The purpose of the CERP is to assist PG&E personnel with safe, efficient, and coordinated response to an emergency incident affecting gas or electric generation, distribution, storage, and/or transmission systems within the PG&E service territory or the people who work in these systems. The CERP contains annexes that, among other details, describe actions undertaken in response to emergency situations.

The CERP uses common emergency response protocols and follows a recognized incident command system. This all-hazards approach applies to any natural disaster or human-caused situation (e.g., fires, floods, storms, earthquakes, terrorist or cyber-attack) that threatens life and property or requires immediate action to protect or restore service or critical business functions to the public.

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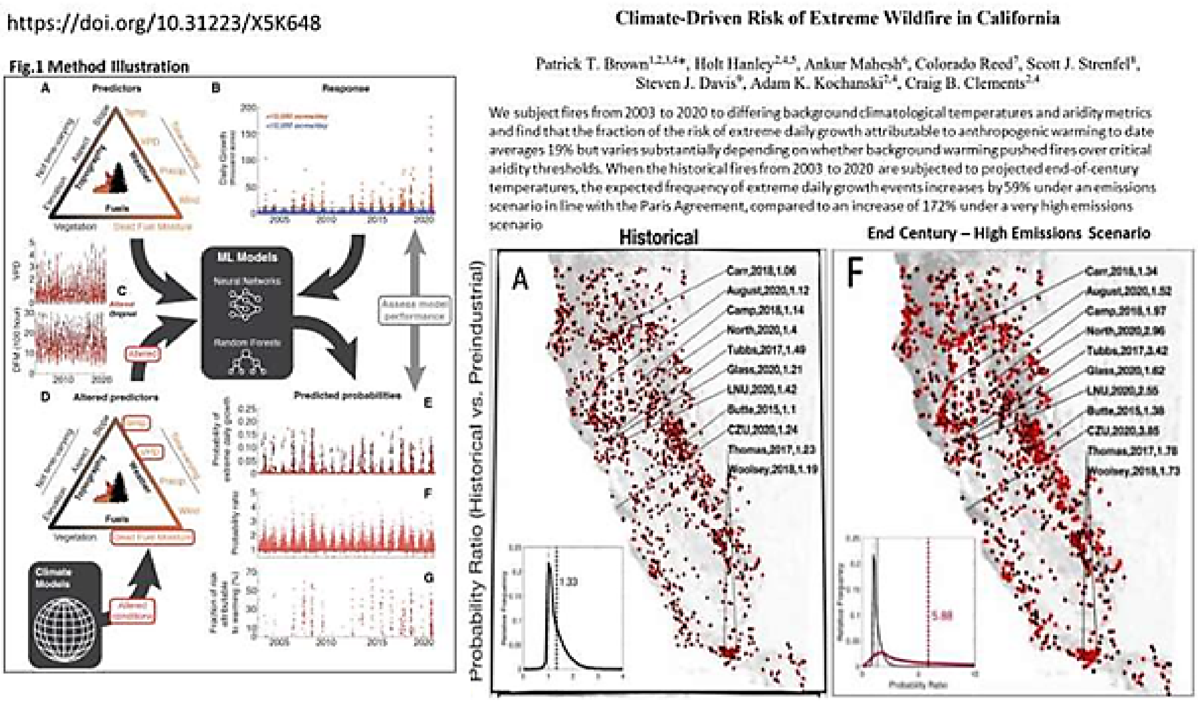
[31] The CERP and its Annexes are available at: PG&E's Community Wildfire Safety Program.

As mentioned in Section 5.3.1, PG&E seeks to incorporate the potential impacts of more extreme conditions in future models. Figure PG&E-5.3.2-1 illustrates the extreme wildfire risk we are studying.

FIGURE PG&E-5.3.2-1:
CLIMATE-DRIVEN RISK OF EXTREME WILDFIRE IN CALIFORNIA



5.4 Summary of Risk Models

In this section, the electrical corporation must summarize the calculation approach for each risk and risk component identified in Section 5.2.1. This documentation is intended to provide a quick summary of the models used. The electrical corporation must provide the following information:

- *Identification (ID): Unique shorthand identifier for the risk or risk component;*
- *Risk Component: Unique full identifier for the risk or risk component;*
- *Design Scenario(s): Reference to design scenarios evaluated with the model to calculate the risk or risk component. These must be defined in Section 5.3;*
- *Key Inputs: List of key inputs used to evaluate the risk or risk component. These can be in summary form (e.g., the electrical corporation may list "equipment properties" rather than listing out equipment age, maintenance history, etc.);*
- *Sources of Data Inputs: List of sources for each input parameter. These must include data sources (such as LANDFIRE) and modeling results (such as wind predictions) as relevant to the calculation of the risk or risk component. If the inputs come from multiple sources, each source should be on a new line;*

- *Key Output Results: List of outputs calculated for the risk or risk component; and*
- *Units: List of the units associated with the key outputs.*

Table 5-4 provides a template for the required information. The electrical corporation must provide a summary of each model in Appendix B.

Table 5-4 below lists PG&E's risk models used in the calculation of overall utility risk and includes a brief description of each one. Design scenarios are not included in this table, but they are discussed in Section 5.3.

TABLE 5-4:
PG&E RISK MODELS

ID	Risk Component	Design Scenario	Key Inputs	Source of Inputs	Key Outputs	Units
UR	Overall Utility Risk	PL1	Outage Program Risk and Ignition/Wildfire Risk	Ignition Likelihood Ignition WFC PSPS Likelihood PSPS Consequence PEDS (EPSS) Likelihood PEDS (EPSS) Consequence	Circuit Segment Level Risk	Dollars ($)
WFR	Ignition/Wildfire Risk (WDRM/WTRM)	PL1	Ignition Probability Ignition Consequence	Ignition Likelihood Ignition/WFC	Circuit Segment Risk	Dollars ($)
OP R	Outage Program Risk	PL1	PSPS Risk PEDS (EPSS) Risk	PSPS Likelihood PSPS Consequence PEDS (EPSS) Likelihood PEDS (EPSS) Consequence	Circuit Segment Risk	Dollars ($)
PSPS R	PSPS Risk	PL1	PSPS Consequence PSPS Likelihood	Historical Meteorology Data Historical PSPS enablement Customer Impacts	SPID Risk Circuit segment Risk Circuit Risk	Dollars ($)
PEDS R	PEDS (EPSS) Risk	PL1	PEDS (EPSS) Likelihood PEDS (EPSS) Consequence	Distribution Event Probability Models Customer Impacts	Circuit Segment Risk	Dollars ($)

TABLE 5-4:
PG&E RISK MODELS
(CONTINUED)

ID	Risk Component	Design Scenario	Key Inputs	Source of Inputs	Key Outputs	Units
PI	Ignition Likelihood	PL1	Equipment models ignition probability Contact from object models ignition probability	Equipment Likelihood of Ignition Contact from Object Likelihood of Ignition	Circuit Segment Likelihood of Ignition	Ignitions/year
PEDS L	PEDS (EPSS) Likelihood	PL1	Equipment models outage probability Contact from object models outage probability	Equipment Likelihood of Outage Contact from Object Likelihood of Outage	Circuit Segment Likelihood of Outage	Ignitions/year
WFC	Ignition/WFC	PL1	Wildfire Hazard Intensity Wildfire Exposure Potential Wildfire Vulnerability Burn Probability	Technosylva FPI Visible Infrared Imaging Radiometer Suite (VIIRS)	Pixel (100 m x 100 m) consequence	MAVF
PSPS C	PSPS Consequence	PL1	PSPS event data Customer data	Historical Meteorology Data	SPID Consequence Circuit segment Consequence Circuit Consequence	Dollars ($)
PEDS C	PEDS (EPSS) Consequence	PL1	Customer impacts	CMI	Circuit Segment Consequence	Dollars ($)

TABLE 5-4:
PG&E RISK MODELS
(CONTINUED)

ID	Risk Component	Design Scenario	Key Inputs	Source of Inputs	Key Outputs	Units
EQI	Equipment Likelihood of Ignition	PL1	Equipment subset likelihood of ignition models	Distribution Asset Data, Historical Outages and Ignitions, PSPS Damages and Hazards, Meteorological data, National Land Cover Database, LANDFIRE surface fuels, HFTD, Vegetation LiDAR, FPI, Real-Time Mesoscale Analysis	100 meter x 100 meter pixel Annual probability of ignition	Ignitions/year
CFOI	Contact from Object Likelihood of Ignition	PL1	Contract from object sub model	Distribution Asset Data, Historical Outages and Ignitions, PSPS Damages and Hazards, Meteorological data, National Land Cover Database, LANDFIRE surface fuels, HFTD, Vegetation LiDAR, FPI, Real-Time Mesoscale Analysis	100 meter x 100 meter pixel Annual probability of ignition	Ignitions/year
BP	Burn Probability	PL1	Rate of Spread Flame Length	Technosylva	100m x 100m pixel destructive potential classification	% of days
WHI	Wildfire Hazard Intensity	PL1	Rate of Spread Flame Length	Technosylva	100m x 100m pixel destructive potential classification	% of days
WEP	Wildfire Exposure Potential	PL1	VIIRS FPI Terrain Difficulty Index	VIIRS FPI Technosylva	100m x 100m pixel destructive potential classification	% of days

TABLE 5-4:
PG&E RISK MODELS
(CONTINUED)

ID	Risk Component	Design Scenario	Key Inputs	Source of Inputs	Key Outputs	Units
WFV	Wildfire Vulnerability	PL1	AFN FPI	AFN FPI	Customer demographics by circuit segment	Counts/circuit segment
PSPS L	PSPS Likelihood	PL1	Historical Meteorology	Weather Data	PSPS event counts by circuit segment	Events/Year
PSPS V	Vulnerability of Community to PSPS	PL1	Customer Demographic data	AFN	Demographic counts per circuit segment	Counts/circuit segment
PEDS L	PEDS (EPSS) Likelihood	PL1	Distribution Event Probability Models	Probability of outage models	Probability of outage	Outages/Year
PEDS V	Vulnerability of Community to PEDS (EPSS)	PL1	Customer Demographic data	AFN	Demographic counts per circuit segment	Counts/circuit segment

5.5 Risk Analysis Results and Presentation

In this section of the WMP, the electrical corporation must present a high-level overview of the risks calculated using the approaches discussed in Section 5.2 for the scenarios discussed in Section 5.3.

The risk presentation must include the following:

- *Summary of electrical corporation-identified HFRAs in the service territory;*
- *Geospatial map of the top risk areas within the HFRA (i.e., areas that the electrical corporation has deemed at high risk from wildfire independent of HFTD designation);*
- *Narrative discussion of proposed updates to the HFTD;*
- *Tabular summary of top risk-contributing circuits across the service territory; and*
- *Tabular summary of key metrics across the service territory.*

The following subsections expand on the requirements for each of these.

5.5.1 Top Risk Areas Within the HFRA

In this section, the electrical corporation must identify top risk areas within its self-identified HFRA, compare these areas to the CPUC's current HFTD, and discuss how it plans to submit its proposed changes to the CPUC for review.[32]

5.5.1.1 Geospatial Maps of Top-Risk Areas Within the HFRA

The electrical corporation must evaluate the outputs from its risk modeling to identify top risk areas within its HFRA (independent of where they fall with respect to the HFTD). The electrical corporation must provide geospatial maps of these areas in accordance with the mapping requirements in the WMP Process Guidelines and Appendix C.

The maps must fulfill the following requirements:

- *Risk Levels: Levels must be selected to show the five distinct levels, with the values based on the following:*
  - *Top 5 percent of overall utility risk values in the HFRA;*
  - *Top 5 to 10 percent of overall utility risk values in the HFRA;*

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32 *Pub. Util. Code § 8386(c)(17).*

- *Top 10 to 15 percent of overall utility risk values in the HFRA;*
- *Top 15 to 20 percent of overall utility risk values in the HFRA;*
- *Bottom 80 percent of overall utility risk values in the HFRA;*

- *Colormap: The colormap of the risk levels must meet accessibility requirements (recommended colormap is Viridis);*
- *County Lines: The map must include county lines as a geospatial reference; and*
- *HFTD Tiers: The map must show a comparison with existing HFTD Tiers 2 and 3 regions.*

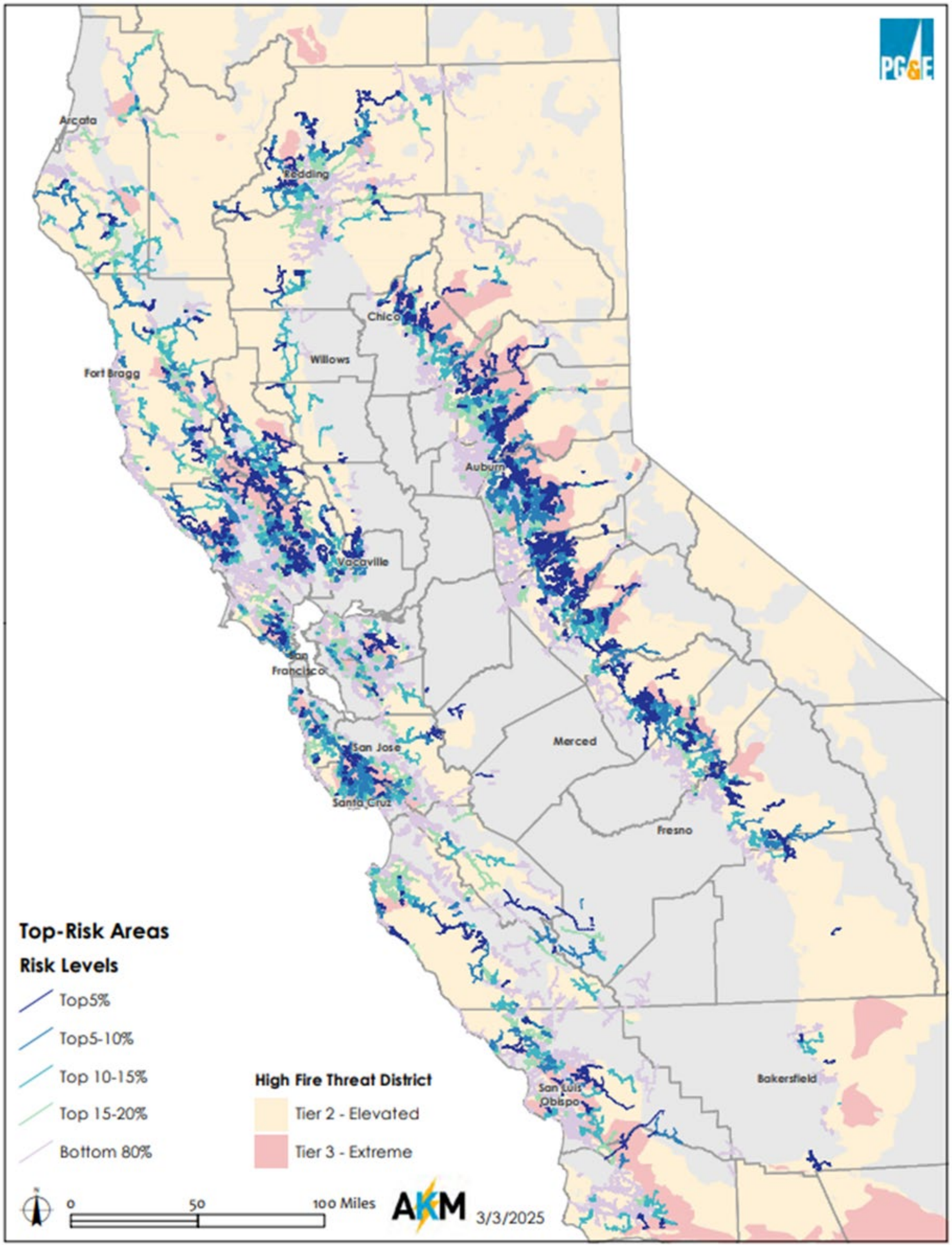
PG&E understands Risk Levels as identified in the WMP Guidelines prompt above to be based on our entire service territory. The risk values have been binned into the five Risk Levels as per the guidelines, representing:

- Top 5 percent;
- Top 5 to 10 percent;
- Top 10 to 15 percent;
- Top 15 to 20 percent; and
- Remaining Bottom 80 percent.

Figure PG&E 5.5.1.1-1 below provides presents the WDRM Output Map with binned risk value status for the HFRA distribution circuit segments. The risk values are used as a factor for identifying potential adjustments to the HFRA.

Using the Risk and WFC views from the WDRM v4 model, geographic locations with high wildfire risk and consequence outside the defined HFTD are identified for additional review and analysis as outlined in Section 5.5.1.2.

FIGURE PG&E-5.5.1.1-1:
WDRM v4 HFRA CIRCUIT SEGMENT RISK MAP



Note: For additional map viewing instructions, please see Appendix C.

5.5.1.2 Proposed Updates to the HFTD

In this section, the electrical corporation must discuss the differences between the electrical corporation-identified top-risk areas within the HFRA and the existing CPUC-approved HFTD.[33] *The HFRA must be comprised of areas identified by the electrical corporations that its risk analysis indicates are at a higher risk than indicated in the current HFTD. Any proposed changes to the HFTD must be mapped in accordance with the requirements in the previous sub-section.*

This discussion at a minimum must include:

- *A discussion of how the electrical corporation analyzed additional areas in HFRA compared to HFTD;*
- *What criteria electrical corporations used to incorporate additional areas into the HFRA;*
- *Associated mitigation changes expected, as applicable; and*
- *A description of the electrical corporation's process for submitting proposed changes to the HFTD to the CPUC, if such changes are desired.*

Top-risk areas are defined as the distribution circuit segments that are in the upper 20th percentile for wildfire risk, based on WDRM v4 risk values. Top-risk areas within the HFRA ("top-risk/HFRA") are defined as those top-risk areas that spatially intersect PG&E's HFRA. Top-risk areas within the existing CPUC-approved HFTD ("top-risk/HFTD") are defined as those top-risk areas that spatially intersect the HFTD.

The key differences between the top-risk/HFRA areas and top-risk/HFTD areas are:

- Of the 2,296 top-risk areas, 2,077 (91 percent) are top-risk/HFRA, 2,063 (90 percent) top-risk/HFTD;
- Of the 2,077 top-risk/HFRA areas, 32 (2 percent) are not top-risk/HFTD; and
- The 32 top-risk/HFRA areas that are not top-risk/HFTD are located throughout the service territory, but are disproportionately clustered in two areas—the South Coast Range between King City and Coalinga (12 areas), and the North Coast Range between Covelo and Arcata (7 areas).

Since PG&E believes that WFC is a more appropriate metric than wildfire risk with which to evaluate areas for potential inclusion in the HFTD, PG&E has chosen to also describe the key differences between top-consequence/HFRA areas and top-consequence/HFTD areas—where top-consequence areas are defined as the areas corresponding to the 100 meter x 100 meter pixels that intersect PG&E overhead

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33 *Pub. Util. Code § 8386(c)(17).*

distribution infrastructure locations and that are in the upper 20th percentile for wildfire consequence, based on WFC v4 consequence values.

The key differences between top-consequence/HFRA areas and top-consequence/HFTD areas are:

- Of the 284,160 top-consequence areas, 282,030 (99 percent) are top-consequence/HFRA, 274,483 (97 percent) are top-consequence/HFTD;

- Of the 282,030 top-consequence/HFRA areas, 7,823 (3 percent) are not top-consequence/HFTD; and

- The 7,823 top-consequence/HFRA areas that are not top-consequence/HFTD are located throughout the service territory, but are disproportionately clustered in two areas—the South Coast Range between King City and Coalinga (2,938 areas), and the North Coast Range between Covelo and Arcata (2,509 areas).

PG&E is not proposing changes to the HFTD in this WMP. However, we are developing a process for identifying areas in our service territory that we believe should be added to or removed from the HFTD. This process will leverage output from PG&E's wildfire consequence modeling. The objectives of this process are to accurately and precisely identify areas of PG&E's service territory that warrant stricter fire safety regulations. We believe that such a process needs to balance analytics vs. expert judgement, internal vs. external expertise, and remote sensing data vs. field observations. We anticipate that this process will closely resemble the process already used by PG&E to assess areas for addition to and removal from its HFRA and will include the following four core components:

- Quantitative wildfire consequence modeling;

- Qualitative, remote sensing-based assessment by PG&E interdisciplinary team including SMEs in wildfire risk analysis, meteorology, and electrical engineering;

- Qualitative, remote sensing -based assessment by external entities with expertise in remote sensing and fire behavior analysis; and

- Qualitative, field-based assessment by PG&E's Public Safety Specialists (PSS), each with extensive, local wildfire operations experience.

In accordance with CPUC requirements, if PG&E identifies areas in our service territory that should be added to or removed from the HFTD, PG&E may submit those proposed modifications to the CPUC via a petition for modification of D.17-12-024, Decision Adopting Regulations to Enhance Fire Safety in the HFTD. The petition for modification would, at a minimum, identify each area proposed for modification, define the area's geographic boundaries, and present rationale for why PG&E believes the modification is warranted.

5.5.2 Top Risk-Contributing Circuits/Segments/Spans

The electrical corporation must provide a summary table showing the highest-risk circuits, segments, or spans[34] *within its service territory. The table should include the following information about each circuit:*

- *Circuit, Segment, or Span ID: Unique identifier for the circuit, segment, or span;*
- *Overall Utility Risk Scores: Numerical value for each risk; and*
- *Top Risk Contributors: The risk components that lead to the high risk on the circuit.*

The electrical corporation must rank its circuits, segments, or spans by circuit-mile-weighted overall utility risk score and identify each circuit, segment, or span that significantly contributes to risk. A circuit/segment/span significantly contributes to risk if it:

1) *Individually contributes more than 1 percent of the total overall utility risk; or*
2) *Is in the top 5 percent of highest risk circuits/segments/spans when all circuits/segments/spans are ranked individually from highest to lowest risk.*

The electrical corporation must include each circuit, segment, or span that significantly contributes to risk in Table 5-5

.[35] *If this table is longer than two pages once populated, the electrical corporation must append the table.*

In response to Critical Issue RN-PGE-26-02, Table 5-5 (now referred to as Table 5-5A), Summary of Top Risk Circuit Segments was revised (now referred to as Table 5-5B) to represent the risk per primary overhead mile and is provided below.

For Table 5-5A, PG&E modeled the circuit segments systemwide to identify the highest risk circuit segments. The top risk contributing distribution circuits segments were determined by assessing the two criteria below established in the WMP Guidelines:

- Individually contributes more than 1 percent of the total cumulative overall utility risk; and
- Contributes to the top 5 percent of cumulative overall utility risk.

PG&E manages most distribution risk assessments and prioritization at the circuit segment level. PG&E has identified the top risk circuit segments that meet the above

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34 *For the section, the electrical corporation may use either circuits, segments, or spans, whichever is more appropriate considering the granularity of its risk model(s).*

35 *This table is a summary of information provided in the applicable data submission. As such, information included in this table must align with the data submission.*

criteria out of the 11,800 systemwide circuit segments that are modeled by the WDRM v4.

PG&E found that:

- There are 0 circuit segments that contribute more than 1 percent of the distribution system overall utility risk (Table 5-5, Column ">1% Total Utility Risk").
- After ranking the circuit segments from highest to lowest overall utility risk, the top 15 circuit segments contribute to the top 5.06 percent of the total overall utility risk. These are the top 15 segments in Table 5-5A.
- In Table 5-5A, PG&E also includes the top 90 circuit segments that contribute to the top 20 percent of total overall utility risk to provide a more comprehensive representation of where the overall wildfire risk per primary overhead mile is concentrated.

Table 5-5A below shows a partial list of our top risk circuit segments. A complete list is available in Appendix F.

In response to Critical Issue RN-PGE-26-02, PG&E has updated Table 5-5A to provide prioritization based on risk-per-mile in Table 5-5B. The outcome of the analysis shows the following:

- There are 7 circuit segments that contribute more than 1 percent of the distribution system overall utility risk per primary overhead mile.
- After ranking the circuit segments from highest to lowest overall utility risk per primary overhead mile, we found that the top two circuit segments contribute to the top 8.28 percent of the total overall utility risk per primary overhead mile. These are the top two segments in Table 5-5B.
- In Table 5-5B, we also include the top 275 circuit segments that contribute to the top 20 percent of total overall utility risk per primary overhead mile to provide a more comprehensive representation of where the overall wildfire risk per primary overhead mile is concentrated.

Table 5-5B is a list of the circuit segments with the highest overall utility risk per primary overhead mile in PG&E's service territory; however, PG&E does not prioritize wildfire mitigations based on this table. Each mitigation program develops a risk-prioritized work plan custom to the program's risk drivers and execution of work. For example, PG&E prioritizes system hardening work based on wildfire risk per mile, with the exception of circuit segments with very short lengths which artificially inflate their risk per mile.

Table 5-5B below shows a partial list of our top risk circuit segments. A complete list is available in Appendix F.

See Revision Notice Response to Critical Issue RN-PGE-26-02 for more information.

TABLE 5-5A:
SUMMARY OF TOP RISK CIRCUIT SEGMENTS

Risk Ranking	Circuit, Segment, or Span ID	Overall Utility Risk Score	Wildfire Risk Score	Outage Program Risk Score	Top Risk Contributors	Total Miles	Version of Risk Model Used
1	CLAYTON 2212681608	99.70	92.60	7.10	Wildfire	33.22	WDRM v4
2	BALCH NO 1 1101105414	91.52	91.51	0.01	Wildfire	7.45	WDRM v4
3	CLOVERDALE 1102672	80.90	78.73	2.18	Wildfire	22.45	WDRM v4
4	PLACERVILLE 21067522	72.83	67.70	5.14	Wildfire	73.53	WDRM v4
5	PLACERVILLE 210611132	67.32	62.26	5.07	Wildfire	44.47	WDRM v4

Note: Adjusted in response of Critical Issues RN-PGE-26-02. See 2026-2028 WMP Revision Notice Response R0 for additional information.

TABLE 5-5B:
SUMMARY OF TOP RISK CIRCUIT SEGMENTS BY RISK PER MILE
FOR RESPONSE TO CRITICAL ISSUE RN PGE 26 02

Risk Ranking	Circuit, Segment, or Span ID	Overall Utility Risk Score	Wildfire Risk Score	Outage Program Risk Score	Top Risk Contributors	Total Miles	Version of Risk Model Used
1	DUNBAR 11034882	176.19	0.18	176.01	PSPS	0.00	WDRM v4
2	PUEBLO 1104968601	126.37	6.92	119.45	PSPS	0.01	WDRM v4
3	ARBUCKLE 110130376	97.21	0.16	97.05	PSPS	0.00	WDRM v4
4	VACAVILLE 111112342	82.76	1.44	81.33	PSPS	0.01	WDRM v4
5	BALCH NO 1 1101CB	72.56	72.55	0.00	Wildfire	0.12	WDRM v4

Note: Adjusted in response of Critical Issues RN-PGE-26-02. See 2026-2028 WMP Revision Notice Response R0 for additional information.

5.6 Quality Assurance and Quality Control

The electrical corporation must document the procedures it uses to confirm that the data collected and processed for its risk assessment are accurate and comprehensive.[36] *This includes, but is not limited to: model, sensor, inspection, and risk event data used as part of the electrical corporation's WMP Program. In this section of the WMP, the electrical corporation must describe the following:*

- *Independent Review: Role of independent third-party review in the data and model quality assurance (QA); and*
- *Model Controls, Design, and Review: Overview of the quality controls in place on electrical corporation risk models and sub-models.*

5.6.1 Independent Review

The electrical corporation must report on its procedures for independent review of data collected (e.g., through sensors or inspections) and generated (e.g., through risk models and software) to support decision making. In this section of the WMP, the electrical corporation must provide the following:

- *Independent Reviews: The electrical corporation's procedures for conducting independent reviews of data collection and risk models;*
- *Additional Review Triggers: The electrical corporation's internal procedures to identify when a third-party review is required beyond the routinely scheduled reviews;*
- *Results, Recommendations, and Disposition: The results and recommendations from the electrical corporation's most recent independent review of its data collection and risk models. This includes the electrical corporation's disposition of each comment; and*
- *Routine Review Schedule: The electrical corporation's routine review schedule.*

Independent Review Triggers: The risk model development process includes both internal and external reviews. In alignment with the model's development schedule outlined in Section 5.6.2, these reviews are conducted as part of the final preparation of a model for approval and use. The external reviews are conducted by an independent third-party to assess how PG&E approach risk and a list of improvement areas are identified for integration into the next model development objectives.

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36 *Pub. Util. Code § 8386(c)(22).*

Additional Review: As outlined in Figure PG&E-5.6.2-1 risk models are reviewed and approved for use by the Wildfire Risk Governance Steering Committee (WRGSC). As part of this step, third-party reviews of data, data collection, and risk models may be initiated outside of the routinely scheduled reviews associated with model validation prior to WRGSC review and approval.

Results, Recommendations, and Disposition:

An independent review of the WDRM v4 was performed by Energy & Environmental Economics (E3). Their report, "E3 Review of PG&E's Wildfire Risk Model Version 4" was issued in July 2024. Some key statements from the report:

Over the last several years, PG&E has continued to improve upon their wildfire risk modeling framework and has built a suite of models that is capable of systematically quantifying the wildfire risk across their system, frequently going above and beyond requirements.

PG&E should continue development of the model to inform the entire risk planning decision space, building on v4 to produce transparent and justifiable company-wide mitigation budgets for short- and long-term planning. While we continue to believe that the combination of informed risk modeling and experienced SME's provides a robust risk management framework, we also believe that the models, as they become more informative, should have an increasing role in the decision-making process.

E3 suggested two areas for improvement of the WDRM:

1) Incorporate temporal dimension in all Sub-Models (Event Probability Models)

   Including a temporal dimension into a ML model allows for the integration of time dependent data, such as seasonal variations in weather and degradation of assets, which improves the accuracy and reliability of forecasts. The PG&E team has already made good progress in this area by updating the Equipment models to allow for a temporal dimension. E3 suggests that this improvement be expanded to the other models within the WDRM to further boost performance. For instance, this would allow the Vegetation model to be aware of the time that has passed since an area had last undergone maintenance.

2) Evaluate the overall effects of implementing p(i|o)

   During discussions with the WDRM team over recent model results, it was shown that in some cases adding the step to calculate the probability of ignition given outage, P(I|O), reduced the predictive performance relative to the probability of outage, P(O), alone. For instance, this was the case for the "primary_conductor_wire_down_cause" subset. The loss of predictive performance for some subsets should be carefully examined, especially in cases where the subset may be a large contributor to ignitions (e.g., primary conductors). In line with E3's overarching recommendation of "right-sizing development efforts" E3 suggests that PG&E evaluate the effectiveness of this modeling direction, and reprioritize it as needed

Routine Review Schedule:

In alignment with the model's development schedule outlined in Section 5.6.2, these reviews are conducted as part of the final preparation of a model for approval and use. Internal reviews are conducted by a range of internal parties including, Enterprise Risk, Internal Audit, and Mitigation Program teams.

5.6.2 Model Controls, Design, and Review

An electrical corporation's risk modeling approaches are complex, with several layers of interaction between models and sub-models. If these models are designed as a single unit, it can be difficult to evaluate the propagation of small changes in assumptions or inputs through the models. The requirements in this section are designed to facilitate the review of models by the stakeholders and Energy Safety, and to allow for more comprehensive retrospective analysis of failures in the system.

The electrical corporations must report on its risk modeling software's model controls, design, and review in the following areas:

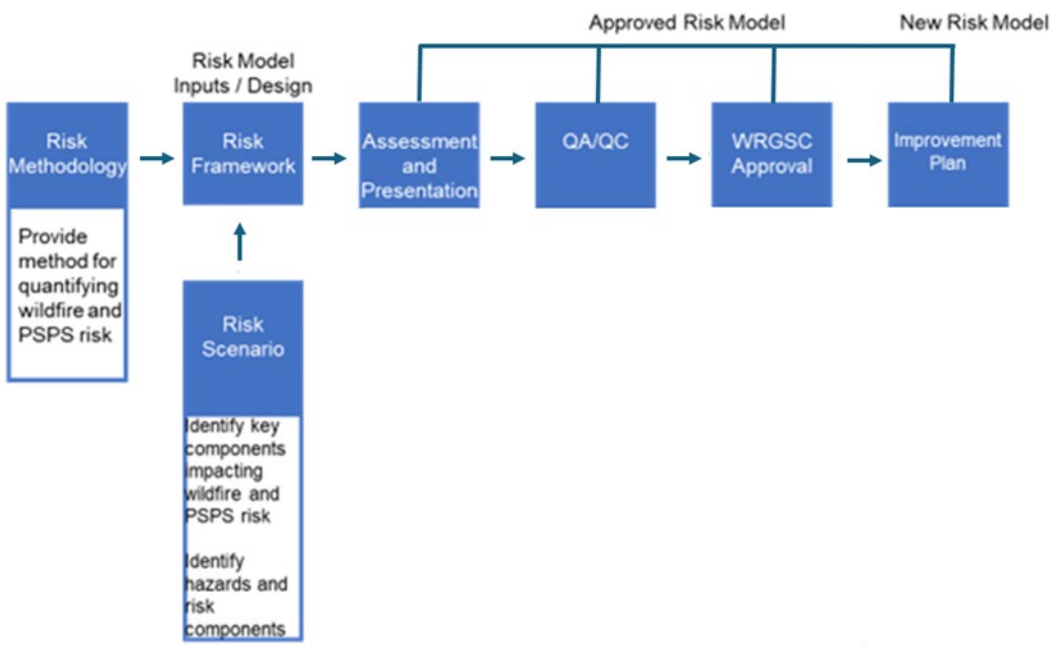
- *<u>Modularization</u>: The electrical corporation must report on the degree to which its software architecture is sufficiently modular to track and control changes and enhancements over time. At a minimum, the electrical corporation must report if it has separate modules to evaluate each of the following:*
  - *Weather analysis;*
  - *Fire behavior analysis;*
  - *Seasonal vegetation analysis;*
  - *Equipment failure;*
  - *Exposure and vulnerability analysis;*
- *<u>Reanalysis</u>: The electrical corporation must describe its capability to provide the results of its risk model based on the operational version of the software (including code and data) on a specific historic day;*
- *<u>Version Control</u>: The electrical corporation must report on how it conforms to industry standard practices in version controlling its risk model and sub-models. At a minimum, the electrical corporation must report on:*
  - *Models and software version controls aligned with industry standard programs, procedures, and protocols;*
  - *Version control of model input data, including geospatial data layers; and*
  - *Procedures for updating technical, verification, and validation documentation.*

Risk Model Lifecycle

Based on the Risk Framework outlined in Section 5.2, the model lifecycle process follows a discrete set of repeatable steps outlined in Figure PG&E-5.6.2-1 below.

The Risk Methodology step outlines the model scope, objectives, and design scenarios discussed in Section 5.1. Next, component probability and consequence models are developed. The development of the component models is an iterative process up until model approval. The draft models are presented for internal review to workplan development teams and independent third parties for validation. The model lifecycle process culminates with a presentation to the WRGSC for final approval. With WRGSC approval, the model results can be used to develop mitigation workplans.

FIGURE PG&E-5.6.2-1:
RISK MODEL LIFECYCLE

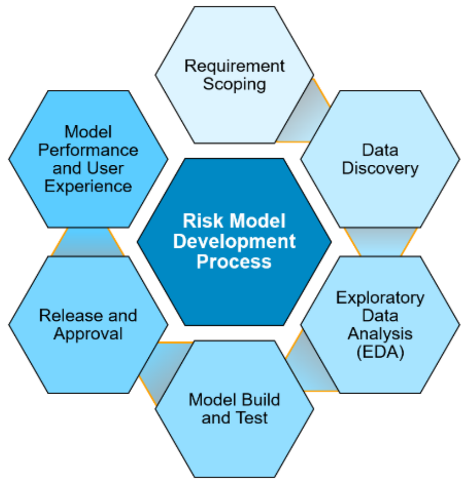


For planning models such as the WDRM and WTRM the model components (probability of ignition, WFC) shown in the Risk Framework in Section 5.2 are discrete but automated software modules. Each module is generated by production code which is version controlled and supported by test code to assure fidelity. In this way, all input data, code, and the resulting model output are version controlled and repeatable. An illustrative example of the modeling steps for the WDRM is provided below.

Risk Model Development Process

All risk models are developed following an iterative process. A high-level view of the development process is shown in Figure PG&E-5.6.2-2.

FIGURE PG&E-5.6.2-2:
MODEL DEVELOPMENT PROCESS



- Requirement Scoping: Encompasses user feedback, new user requirements, potential performance improvements, and new or desired causal information to set model development goals.
- Data Discovery: Researching new data sources, obtaining updates to refresh existing data sources, and cleaning and validating data for potential model use.
- Exploratory Data Analysis: Data analysis and investigation to determine fitness for modeling.
- Model Build and Test: Successive builds of proposed models verified for performance against independent testing data.
- Release and Approval: Candidate release models are published to the user community for critique. Viable release candidates are presented through a governance process to gain approval for general release in support of wildfire mitigation work planning.
- Model Performance and User Experience: The approved model is monitored for performance against actual events and user feedback is collected to inform the next iteration of model development.

This is a simplified description of the risk modeling process. At any step in development, knowledge gained can require an iteration back to an earlier process step or even to a reevaluation of model development scope.

Modularization

The risk models are designed to employ multiple layers of modularization to manage changes and enhancements. As outlined in Section 5.2, the WDRM and the WTRM are comprised of two core modules: a Consequence model and a set of Event Probability models.

The Event Probability models support the distribution and transmission by predicting where electrical assets are most likely to experience an abnormal operating event that results in an outage or ignition event. Event Probability models generally fall into two categories: Equipment Asset and Contact From Object models.

Equipment Asset Models consider event history and contributing factors to predict failure of specific types of electrical equipment. Each asset model uses a unique set of inputs (covariates) from a pool of asset attributes and environmental conditions. For some assets, unique causal models (sub-sets), are produced for specific types of failures.

Contact From Object Models consider event history and contributing factors to predict failure caused by contact from foreign objects with electrical assets. Each contact model uses a unique set of inputs (covariates) from a pool of object attributes and environmental conditions. All contact models provide unique causal models (sub-sets) for specific types of contact failures.

The WFC Model supports the WDRM and WTRM by estimating the likely outcome of an ignition originating at the geographical location of any electrical asset. The consequence model is trained to historical fires, while considering: Technosylva fire simulations, PG&E Meteorology's FPI index, dry wind conditions, and other fuel and weather conditions. In addition, the consequence estimates are adjusted for population Egress and fire-fighting Suppression impacts.

Reanalysis

The risk models (WDRM, WTRM, PSPS, and EPSS) are released to end-users for planning as a static data-cube of probability, consequence, and risk results, typically through a Foundry-based user interface. The risk models are not directly executable by an end-user. However, all code and datasets used to generate a risk model version release are archived such that the results could be regenerated if necessary.

Version Control

Throughout the model development multiple versioning and archiving controls were followed for the risk models. The WDRM versioning control processes were specifically subjected to an internal PG&E audit following the release of WDRM v3 to assure compliance with PG&E IT standards relating to version control.

5.7 Risk Assessment Improvement Plan

A key objective of the WMP review process is to drive year-over-year continuous improvement. In this section, the electrical corporation must provide a high-level overview of its plan to improve both programmatic and technical aspects of its risk assessment in at least four key areas:

- *Risk Assessment Methodology: Wildfire and PSPS risk assessment methodology and its documentation, including both quantitative and qualitative approaches;*
- *Design Basis: Justification of design basis scenarios used to evaluate the risk and its documentation;*
- *Risk Presentation: Presentation of risk to stakeholders, including dashboards and statistical assessments; and*
- *Risk Event Tracking: Tracking and reconstruction of risk events and integration of lessons learned.*

The overview must consist of the following information, in tabulated format:

- *Key Area: One of the four key areas identified above;*
- *Title of Proposed Improvement: Brief heading or subject of the improvement;*
- *Type of Improvement: Technical or programmatic;*
- *Anticipated Benefit: Summary of anticipated benefit and any other impacts of the proposed improvement; and*
- *Timeframe and Key Milestones: Total timeframe for undertaking the proposed improvement and any key milestones.*

In addition, the electrical corporation must provide a concise narrative of its proposed improvement plan (maximum of five pages per improvement) summarizing:

- *Problem Statement: Description of the current state of the problem to be addressed;*
- *Planned Improvement: Discussion of the planned improvement, including any new/novel strategies to be developed and the timeline for their completion;*
- *Anticipated Benefit: Detailed description of the anticipated benefit and any other impacts of the proposed improvement;*
- *Region Prioritization (Where Relevant): Reference to risk-informed analysis (e.g., local validation of weather forecasts in the HFTD) demonstrating that high-risk areas are being prioritized for continued improvement; and*
- *Supporting documentation (as necessary).*

Table 5-6 below shows our risk assessment improvement plan.

TABLE 5-6:
RISK ASSESSMENT IMPROVEMENT PLAN

Key Risk Assessment Area	Proposed Improvement	Type of Improvement	Expected Value Add	Timeframe and Key Milestones
Conflagration Risk Modeling	Investigate development of improved representation of conflagration risk in consequence model	Technical	Improved quantification of risk related to urban conflagration	By end of 2027
Specificity of Vegetation Probabilistic Models	Investigate improved granularity of vegetation probabilistic models	Technical	Improved specificity of hazard tree identification for work plans	By end of 2027
Improved Asset Failure Probabilistic Models	Investigate opportunities to improve individual asset failure models	Technical	Improved effectiveness of mitigation workplans	By end of 2027

Improvement Area Narratives

Conflagration Risk Modeling – 1: Improve quantification of conflagration risk in the WFC model.

Problem Statement

Wildfire spread modelling technics, such as those used in the development of PG&E's WFC Model, use fuel layers, which represent the range of vegetation layers a wildfire could encounter. Due to the complex dynamics of the fuels and fire behavior of a burning structure, this impact and influence of structures as fuel are not fully accounted for in current modeling. This area of opportunity continues to be a focus of both academic and industry work.

Planned Improvement: Planned development would identify potential area and approaches for improvement of the WFC model that could be included in the next version of the wildfire risk models.

Anticipated Benefit

While the current WFC model identifies locations where fast-moving fire could enter communities near to the wildfire urban interface, improved quantification of the characteristics of the urban conflagration will only improve the prioritization of locations and provide valuable insight to tribes, counties, and cities as they develop fire mitigation strategies regardless of the source of the potential fire.

Specificity of Vegetation Probabilistic Models – 2: Investigate potential improvements to vegetation failure models with nascent satellite data.

Problem Statement

PG&E's vegetation failure models are highly predictive at the 100-meter square granularity. Nevertheless, consistent with our stand that catastrophic wildfire will stop, the granularity and information under development and becoming commercially available to better identify vegetation characteristics continues at a rapid pace. This new data has the potential to improve both the granularity and specificity of the vegetation failure models. This is a key area of focus in the preparation of the next version of the Wildfire Risk Models.

Planned Improvement

Planned development would investigate and identify potential data sets and modeling methods to improve the granularity and specificity of the vegetation probabilistic models.

Anticipated Benefit

Potential benefits of improved vegetation models would include more effective vegetation mitigation plans resulting in fewer vegetation related outages and ignitions.

Improved Asset Failure Probabilistic Models – 3: Investigate potential improvements to asset failure models.

Problem Statement

Over the first four iterations of the WDRM v4 the specificity and predictive power of the asset failure models has improved to 22 individual sub-models. Nevertheless, improvements in asset data and systems have the potential to improve the characterization of assets and asset condition in the models. This new data has the potential to improve both the granularity and specificity of the asset failure models. This is a key area of focus in the preparation of the next version of the Wildfire Risk Models.

Planned Improvement

Planned development would investigate and identify potential data sets and modeling methods to improve the granularity and specificity of the asset probabilistic models.

Anticipated Benefit

Potential benefits of improved asset models would include more effective asset mitigation plans resulting in fewer asset related outages and ignitions.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 6

WILDFIRE MITIGATION STRATEGY DEVELOPMENT

6. Wildfire Mitigation Strategy

In this section, the electrical corporation must provide a high-level overview of the risk evaluation processes that inform its selection of a portfolio of activities, as well as its overall wildfire mitigation strategy.[37] *The electrical corporation's processes and strategy must be designed to achieve maximum feasible risk reduction*[38] *and meet the goal(s) and plan objectives stated in Sections 3.1–3.2. Sections 6.1 and 6.2 below provide detailed instructions.*

6.1 Risk Evaluation

6.1.1 Approach

In this section, the electrical corporation must provide a brief narrative of its risk evaluation approach, based on the risk analysis outcomes presented in Section 5. This narrative helps inform the development of a wildfire mitigation strategy that meets the goal(s) and plan objectives stated in Sections 3.1-3.2. The electrical corporation must indicate and describe in the narrative whether its risk evaluation approach meets or uses any industry-recognized standards (e.g., ISO 31000), best practices, and/or research.

The electrical corporation must describe the risk evaluation approach in a maximum of two pages, inclusive of all narratives, bullet point lists, and any graphics.

PG&E's risk management is based on a quantitative risk assessment to determine our overall utility risk from wildfire and outage program events, consistent with the CPUC's RDF. Our approach includes an ongoing effort to continuously evaluate risk. This effort builds on an iterative process that includes risk identification, evaluation of the impact of those risks on our system and the community, addressing those risks through mitigation and control programs, and monitoring the effectiveness of our risk mitigation and management programs.

PG&E's approach to risk evaluation is informed by: (1) comprehensive monitoring and data collection through which we collect meteorological and environmental data and analyze history and trends; (2) a robust asset inspection program that includes inspections performed by drone, helicopter, or aerial lift, with desktop image review or visual review by an inspector on the ground to identify asset conditions which could lead to an ignition; (3) a thorough investigation of all CPUC-reportable ignitions to determine

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37 *Pub. Util. Code §§ 8386(c)(3), (12)-(14).*

38 *"Maximum feasible" means, in accordance with Pub. Util. Code § 326(a)(2), "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors."*

the root cause and any gaps in our defenses; and (4) wildfire risk models that are built to help guide longer-term mitigations that improve the resiliency of our systems.

PG&E uses two types of models to address the dynamic wildfire risk across our service territory: operational models and long-term planning models. We employ operational models for operational mitigations such as PSPS and EPSS. These models produce outputs such as the FPI, a short-term forward-looking view, to determine where wildfire risk is elevated. These operational models help guide how we operate the grid. We use long-term planning models to develop and implement resilience mitigations in areas of high risk to reduce that risk on a more permanent basis.

Our mitigation strategy is risk informed, executable, and aligned to available resources. We accomplish this by engaging key stakeholders and following a defined decision-making process.

As indicated above in Section 5.1.1, PG&E recently achieved ISO 55001 re-certification for demonstration of its conformance with the international standard for asset management, which includes risk identification and analysis and proactive risk management.

6.1.2 Risk-Informed Prioritization

In making decisions involving risk mitigation, the electrical corporation must identify and evaluate where it can make investments and take actions to reduce its overall utility risk. The electrical corporation must develop a prioritization list based on overall utility risk.

In this section, the electrical corporation must:

- *Describe how it selects circuit segments of its service territory at risk from wildfire for potential activities, including, at a minimum, the following:*
  - *Geographic scale used in prioritization (i.e., regional, circuit, circuit segment, span, asset);*
  - *Statistical approach used to select prioritized areas (e.g., circuit segments in top 20 percent for risk, circuit segments in top 20 percent for consequences); and*
  - *Feasibility constraints (e.g., limitations on data resolution, jurisdictional considerations, accessibility).*

Present a list that identifies, describes, and prioritizes circuit segments of its service territory at risk from wildfire for potential activities based solely on overall utility risk, including the associated risk drivers. Associated risk drivers must be ranked in order of most impactful to risk.

PG&E considers wildfire risk to our service territory based on geographic, statistical, and feasibility factors and uses this information to prioritize mitigations. We recognize that there are varying levels of risk across the system and use risk models to prioritize our work using the differing levels of granularity described below.

Geographic Scale

The HFTD areas have an elevated risk of utility-associated wildfires. Given that the wildfire risk is predominantly concentrated in the HFTD, PG&E annually reassesses the HFTD and has created and reviews an HFRA zone, which includes HFTD and select areas the HFTD does not cover. For our mitigation programs, we cover HFTD and HFRA and collectively call these areas HFTD/HFRA. The HFTD/HFRA map is the highest-level geographic scale PG&E uses in evaluating utility risk to our service territory. All subsequent prioritization occurs within areas designated as HFTD and HFRA and, for certain mitigations, in buffer areas adjacent to the HFTD and HFRA.

In our distribution risk model (WDRM v4), we narrow the geographic scale to focus on assets and structures located within HFTD/HFRA areas. For asset and structure equipment failures, we determine the risk for each individual asset. For contact from object failures, including contact from vegetation, animals, and third party, a risk value is assigned to a geographic pixel. A pixel is defined as an area that measures 100-meter x 100-meter.

All overhead conductor and equipment risk, along with contact from object pixel risk, is aggregated to either the circuit segment level or the structure level. PG&E has widely varying circuit lengths and aggregating to the circuit segment level, which generally represents segments of circuit between protection devices, provides a much more granular representation of risk and is used for operational, planning, and work execution in these select locations. Programs such as undergrounding and overhead system hardening are risk prioritized at the circuit segment level. PG&E prioritizes risk at the asset level for component-based programs such as non-exempt fuse replacement.

For Vegetation Management (VM) work, PG&E determines the vegetation risk and WFC at each circuit segment, for the purposes of inspection planning.

For transmission work, the wildfire transmission risk model (WTRM v2) also provides a granular scale similar to the distribution risk model.

Statistical Approach

PG&E determines wildfire risk by developing prioritized risk buydown curves using our two risk models (WDRM v4 and WTRM v2). The risk buydown curve identifies locations where investing in mitigations will reduce the most risk being assessed. For example, the risk buydown curve is the model output we rely on to develop mitigation tranches, where the first tranche will reduce the most risk and subsequent tranches will reduce less risk.

For long-term mitigation work planning, wildfire risk is typically used to prioritize work. However, some mitigation and inspection programs are more sensitive to short-term environmental changes around the grid equipment assets. Therefore, short-term planning is often prioritized by only the consequence portion of the risk model rather than the risk score (event probability multiplied by event consequence).

Feasibility Constraints

Information from our risk models informs our decision-making. However, in certain instances, we also incorporate feasibility considerations. Key considerations include topography (gradient, hard rock, water crossings, etc.), permitting issues, environmental concerns, customer refusals, execution, and consideration of the community impact of our planned mitigation work.

Our undergrounding program, for example, needs to balance the risk reduction for undergrounding a specific segment of overhead line along with potential feasibility constraints such as hard rock, steep gradients, and water crossings. Since our goal is to remove as much risk from the system as quickly as possible, in certain circumstances we may choose to overhead harden a circuit segment or portion of a circuit segment because of feasibility constraints. In these cases, we continue to monitor the risk profile of the overhead hardened segment and ensure that additional programs such as EPSS are in place to mitigate the risk.

Our VM activities are constrained by weather conditions, wildfires and accessibility restrictions, permitting delays/restrictions, and customer concerns. Because of these constraints, our VM workplans often include a larger volume of risk-prioritized work than we will execute so there is sufficient high-priority work to continue reducing system risk. Our VM teams also consider and balance conflicts among risk reduction, fire safety regulations, environmental regulations, and forest practice rules. Where we have constraints, we continue to monitor the risk through our VM Inspection Program.

Our transmission activities require coordination with the California Independent System Operator (CAISO) and are also subject to availability of transmission clearance windows.

Prioritized Risk Areas in PG&E's Service Territory

PG&E prioritizes all HFTD/HFRA areas when considering mitigation activities. For consistency in reporting, PG&E determined that 90 circuit segments contribute to the top 20 percent of cumulative overall utility risk as shown in Table 6-1 below. Table 6-1 is a partial list of PG&E's Prioritized Areas based on Overall Utility Risk. A complete list is available in Appendix F.

TABLE 6-1:
PG&E PRIORITIZED AREAS BASED ON OVERALL UTILITY RISK

Priority	Circuit Segment and/or Span ID	Length (miles)	Overall Utility Risk	Wildfire Risk	Outage Program Risk	Percent of Overall Utility Risk	Associated Risk Driver
1	CLAYTON 2212681608	33.22	99.70	92.60	7.10	0.50%	Equipment failure Vegetation contact Contact from object
2	BALCH NO 1 1101105414	7.45	91.52	91.51	0.01	0.46%	Equipment failure Vegetation contact Contact from object
3	CLOVERDALE 1102672	22.45	80.90	78.73	2.18	0.40%	Vegetation contact Equipment failure Contact from object
4	PLACERVILLE 21067522	73.53	72.83	67.70	5.14	0.36%	Vegetation contact Equipment failure Contact from object
5	PLACERVILLE 210611132	44.47	67.32	62.26	5.07	0.34%	Vegetation contact Equipment failure Contact from object

6.1.3 Activity Selection Process

After the electrical corporation creates a list of top-risk contributing circuits/segments/spans (Section 5.5.2) and prioritized circuit segments based on overall utility risk (Section 6.1.2), the electrical corporation must then identify potential mitigation strategies. It must also evaluate the benefits and drawbacks of each strategy at different scales of application (e.g., circuit, circuit segment, system-wide). In this section of the WMP, the electrical corporation must provide the basis for its decisions regarding which activities to pursue.

The electrical corporation must consider appropriate activities depending on the local conditions, physical setting, and the risk components that create the high-risk conditions. There may be a wide variety of potential activities, such as:

- *Engineering changes to grid design;*
- *Discretionary inspection and/or maintenance of existing assets;*
- *Vegetation clearances beyond minimum regulatory requirements;*
- *Alternative operational policies, practices, and procedures; and*
- *Improved emergency planning and coordination.*
- *The electrical corporation must also evaluate mitigating risk through a portfolio of combined multiple activities.*

The electrical corporation is expected to use its procedures discussed in Section 5 to:

- *Develop potential activity approaches to address each risk;*
- *Characterize the potential activities to provide internal decision makers with information required to support decision making (e.g., costs, material availability), including an assessment of uncertainties; and*
- *Document the results of the evaluation.*

The electrical corporation must develop a proposed schedule for implementing each activity and proposed metrics to monitor implementation and effectiveness of the activities. The following subsections provide specific requirements.[FN]]

6.1.3.1 Identifying and Evaluating Activities

The electrical corporation must describe how it identifies and evaluates options for mitigating wildfire and outage program risk at various analytical scales, consistent with the CPUC guidelines associated with the RDF established in the RDF Proceeding.[FN] The electrical corporation must present the risk mitigation identification procedure it plans on using during the course of the three years filed in the Base WMP. If the electrical corporation is required to submit a RAMP filing to the CPUC, the risk mitigation procedure provided must be consistent with either its most recent RAMP filing or its upcoming RAMP filing. The electrical corporation must describe the following:

- *The procedures for identifying and evaluating activities (comparable to Risk-Based Decision-Making Framework, row 26),[FN] including the use of risk buy-down estimates (e.g., risk-spend efficiency, benefit-cost ratio) and evaluating the benefits and drawbacks of activities;*
- *To the extent possible, multiple potential locally relevant activities that address local wildfire risk drivers (see Risk-Based Decision-Making Framework, rows 11 and 14);[FN]*
- *The approach the electrical corporation uses to characterize uncertainties and how the electrical corporation's evaluation and decision-making process incorporates these uncertainties (see Risk-Based Decision-Making Framework, rows 26 and 30);[FN]*
- *Two or more potential initiative or activity portfolios for each risk driver included in the list of prioritized circuit segments (Table 6-1 in Section 6.1.2), including the following information:*
  - *The initiatives and activities;*
  - *Expected risk reduction and impact on individual risk components:*
    - *Where mitigations can be feasibly deployed in combination, the electrical corporation must compare these portfolios of activities (e.g., covered*

conductor, vegetation management, asset inspections, and protective device and equipment settings versus undergrounding, secondary hardening, and asset inspections);

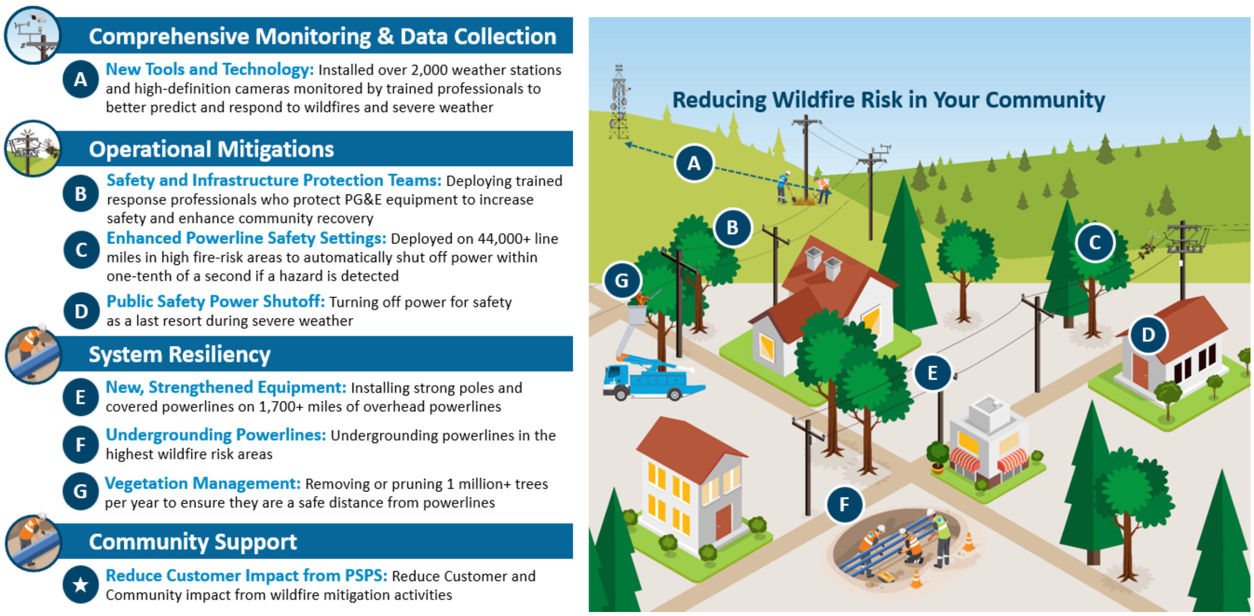
- *Estimated implementation costs:*
  - *Where activities can be feasibly deployed in combination, the utility must compare these portfolios of activities (e.g., covered conductor, vegetation management, and protective device and equipment settings versus undergrounding and secondary hardening)*
- *Relevant uncertainties and associated potential impacts, including solutions on how to reduce the potential impacts;*
- *Implementation schedule;*

- *How the electrical corporation uses MAVFs, CBA, and/or other specific risk factors (as identified in relevant CPUC Decisions) in evaluating different activity alternatives;*
- *This must include how the electrical corporation considers cost efficiencies when evaluating activities, including overlap with planned or projected upgrades due to future grid needs (e.g., load capacity, peak demand, system flexibility).[FN]*
- *How the electrical corporation defines different aspects of risk considerations, including: Risk Scaling, Risk Tolerance, Uncertainty, and Tail Risk in its risk mitigation strategies;[FN]*
  - *Must break out each by safety and reliability (PSPS and PEDS), as applicable; and*
  - *Must include a discussion of how each aspect impacts mitigation selection and prioritization.*

PG&E's 2026-2028 WMP builds on our substantial efforts over the last several years to address the extreme and evolving risk of catastrophic wildfire in our service territory. While we have historically addressed wildfire risk, we have taken significant additional steps starting in 2019 to address the ever-increasing threat of wildfire, by, among other actions, standing up a Wildfire Safety Operations Center, expanding wildfire safety inspection programs, increasing and refining VM programs, installing weather stations and high definition wildfire cameras, installing system hardening and resiliency, and initiating the PSPS and EPSS activities. Thus, as we approach the 2026-2028 WMP period, we are building on the robust wildfire mitigation risk strategy and mitigations already in place.

PG&E's mature wildfire risk reduction strategy is—by necessity—never static. The dramatic changes in weather and fast-moving wildfire risk require PG&E to continuously monitor the risk and update our strategies. PG&E manages and reduces ignition risk through operational mitigations while we implement permanent risk reduction strategies, such as undergrounding and other system hardening work through our resiliency programs. Since no single wildfire mitigation is sufficient to eliminate the wildfire risk, PG&E layers multiple types of mitigations to reduce as much wildfire risk as possible, as set forth in Figure PG&E-6.1.3.1-1 below:

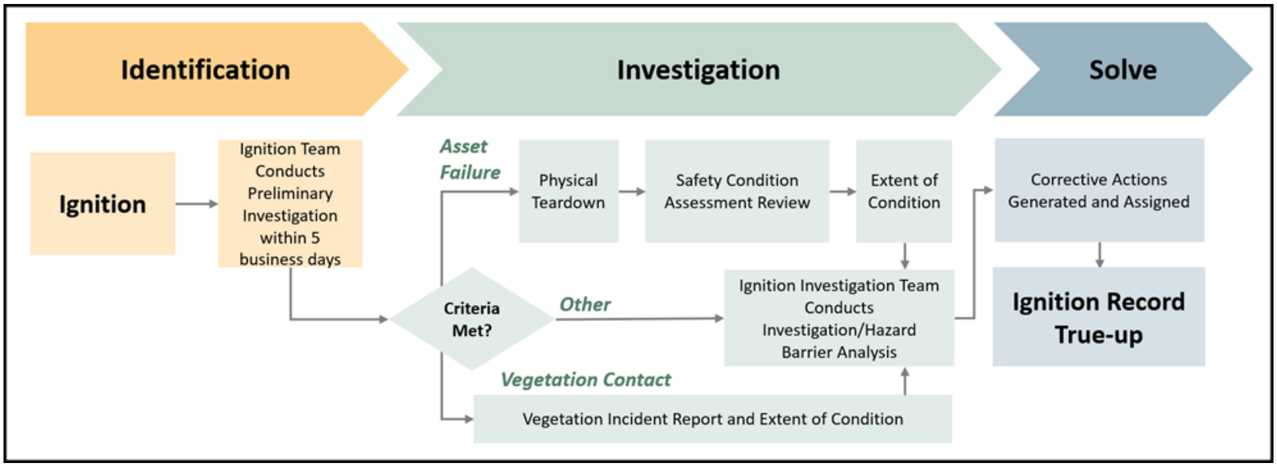
FIGURE PG&E-6.1.3.1-1:
LAYERS OF WILDFIRE PROTECTION



Under our approach to layering protection, mitigations evolve through improvements, optimizations, or new capabilities. We continuously monitor for gaps in our layers of protection to strive for full coverage. In April 2021, PG&E established an Ignition Investigations team to bring expertise and forensic analysis to this critical work and to inform preventative wildfire mitigation efforts. This team is also trained in wildfire cause determination and origin. PG&E teams investigate all CPUC-reportable ignitions to determine the cause of the ignition and where PG&E's risk mitigations and controls failed to prevent the ignition. The teams conduct an asset failure analysis which includes physical inspections, condition inspections, and performance testing. PG&E also reviews the fault data and analyzes gaps in protection devices and their settings. PG&E applies the team's findings to its risk mitigation portfolio and uses the information to evolve its efforts, in a continuous effort to improve.

The Ignition Investigation team's process is summarized in Figure PG&E-6.1.3.1-2 below.

FIGURE PG&E-6.1.3.1-2:
SUMMARY OF IGNITION INVESTIGATION PROCESS



PG&E evolves its mitigation plans to incorporate the learnings obtained from ignitions investigation process, as set forth in Figure PG&E-6.1.3.1-3 below.

FIGURE PG&E-6.1.3.1-3:
ONGOING REVIEW AND IMPROVEMENT OF MITIGATIONS TO ADDRESS GAPS

Risk Based Framework Used to Plan and Schedule New Work

PG&E's WMP is based on the CPUC's approved risk framework. PG&E utilizes a structured, risk-informed decision-making framework that is aligned with the CPUC's RDF approved in D.22-12-027 and D.24-05-064 to identify and evaluate existing mitigations and add new ones. This process integrates both qualitative and quantitative analyses to optimize resource allocation, while ensuring compliance with regulatory mandates.

PG&E submitted its most recent RAMP in May 2024.[39] PG&E is the first utility to implement the CPUC's new RDF in its RAMP. PG&E's 2024 RAMP includes a CBA, consistent with the principles in the RDF.[40] Using this methodology, PG&E performed a risk analysis of the Enterprise Risks on its Corporate Risk Register and used the calculated risk values to identify and rank its top safety risks to be evaluated in the RAMP and develop the proposed mitigation to address these risks. PG&E's RAMP is focused on systemwide wildfire risk, while this WMP is focused on HFTD/HFRA areas.

PG&E has adopted consistent treatment, and definitions, of different risk considerations including Risk Attitude, Risk Tolerance, Uncertainty and Tail Risk in its risk assessment and mitigation strategies. PG&E's overall approach is focused on reducing the potential for catastrophic risk events. Central to this approach is PG&E's ability to quantify, via its risk assessments, the possibility of Tail Risk events, defined as low frequency, high consequence events. The primary way that PG&E achieves this in its risk modeling is by adopting a risk-averse Risk Attitude—also known as Risk Scaling-Function. PG&E calculates risk and risk reduction expressed in dollars consistent with the CBA. PG&E further elaborates on the implications of this approach on the development of PG&E's Risk-Scaling Function in its 2024 RAMP. Consistent with the CPUC's direction in D.21-11-009, PG&E's RAMP models PSPS and EPSS events as risk events, although PG&E considers PSPS and EPSS as mitigations for the wildfire risk.

Procedure for Identifying and Evaluating Activities

PG&E identifies and evaluates activities taking into consideration the CBA, the results of the Ignition Evaluation Analysis, other relevant factors regarding the ability to do the work, and the expected risk reduction that would be achieved by that mitigation.

PG&E calculates a Cost-Benefit Ratio (CBR) for each mitigation, which incorporates cost estimates and the effectiveness of each mitigation. PG&E's Investment Planning group leverages the CBRs and the RDF to prioritize the proposed investments to achieve risk reduction at a reasonable cost as part of its GRC forecast. The funding approved in the GRC decisions guides the pace of the resilience work. PG&E's 2027-2030 GRC overlaps with two years of the 2026-2028 WMP. PG&E's proposed

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39 PG&E 2024 RAMP Report (May 15, 2024), A.24-05-008.

40 In D.22-12-027, the CPUC replaced the MAVf with the CBA a cost-benefit approach that includes standardized dollar valuations from risk events and required the utilities to implement the modified RDF to assess and rank risks and mitigations with the RDF starting with PG&E's 2024 RAMP. D.22-12-027, pp.1, 24.

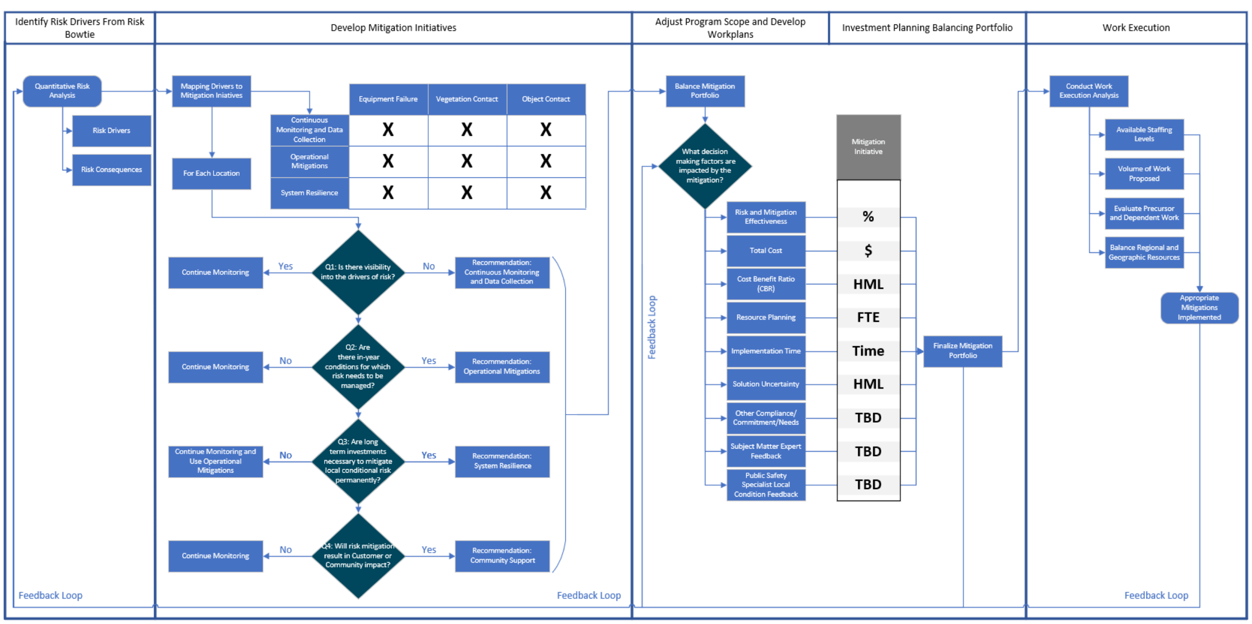
wildfire mitigations in this WMP are consistent with those that will be proposed in the GRC.

While PG&E used the CBRs to prioritize its suite of mitigations, it does not select its mitigation strategy solely based on the CBRs. As noted in RDF line 26, mitigation selection is influenced by other important factors, including, but not limited to, funding availability, labor resource, technology, planning and construction lead time, compliance requirements, risk tolerance thresholds, operations and execution consideration and modeling limitation and/or uncertainties affecting the analysis. SME judgment is integrated into this process through cross-functional working groups. These working groups help ensure mitigation activity selection leverages both quantitative risk assessments and qualitative operational insights. When selecting a mitigation, PG&E also considers relevant local factors on a case-by-case basis.

PG&E's Investment Planning organization works in concert with functional groups (e.g., undergrounding) to develop longer-term program budgets that balance forecasted mitigation work with expected funding. In general, available funding for wildfire mitigation work, including PSPS, is determined via the GRC and Transmission Operator application proceedings and can vary from what is forecasted by Investment Planning. Another consideration in the selection of risk mitigation activities is the availability, or lack thereof, of regional resources that are needed to execute the work.

PG&E's mitigation selection process is summarized in Figure PG&E-6.1.3.1-4:

FIGURE PG&E-6.1.3.1-4:
MITIGATION SELECTION, PLANNING AND EXECUTION



Following this process, PG&E continuously evaluates the effectiveness of the mitigations to determine which should be enhanced and which should phase out. Through our ignition analysis described above, if we determine that the current portfolio of mitigations was unable to prevent a specific ignition, we address the gap by either developing a new mitigation or modifying an existing mitigation. An example of this is our development of Downed Conductor Detection (DCD) for high impedance faults. Once a need for a new mitigation is determined, PG&E uses the risk-buydown curve approach to develop the scope for the new mitigation. PG&E then determines the appropriate implementation timeline, balancing maturity of the technology, available resources, and cost considerations for the new mitigation. Concurrently, the mitigation plan is presented and discussed within the existing Wildfire Risk Governance framework—providing a comprehensive and iterative approach to prioritizing mitigation activities.

Addressing Localized Wildfire Risk Drivers

PG&E's selection of initiatives takes into consideration local risk drivers. Row 11 of the RDF requires risk drivers to reflect current and forecasted conditions and characteristics of assets. Row 14 of the RDF states that:

> [T]he determination of Tranches will be based on how the risks and assets are managed by each utility, data availability and model maturity, and strive to achieve as deep of a level of granularity as reasonably possible.[41]

PG&E has adopted this guidance by developing tranches of risks based on how risks and assets are managed. Wildfire risk is separated by location and facility type, with further granularity established for the distribution risk based on the WDRM v4. This framing results in 35 tranches within HFTD/HFRA. The tranches are separated by location, facility types, and whether the facilities are distribution or transmission.[42]

Risk Uncertainty

CBRs developed for distribution mitigations are subject to considerable modeling uncertainty due the period of the data and the dynamic nature of the threat environment.[43] PG&E seeks to account for this uncertainty by regarding CBRs as one of several key factors in its risk-informed decision-making process, consistent with the RDF.

Mitigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis.[44]

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41 D.22-12-027, Appendix A, p. A-13, No. 14.

42 PG&E 2024 RAMP Report (May 15, 2024), (PG&E-4), pp. 1-23 to 1-25.

43 PG&E 2024 RAMP Report (May 15, 2024), (PG&E-4), p. 1-16.

44 D.22-12-027, Appendix A, Row 26, p. A-16.

RDF Row 30 requires the utilities to “identify critical parameters and assumptions made in performing the risk analysis and explain why such parameters are critical.” Our risk models have a probability of event for each risk driver; an example of this is the animal contact risk driver. For this risk driver, we use the probability of event—animal contact—and then the consequence of the event. We then determine where on the high-risk circuit segments to install a mitigation (in this example, an animal guard) to address that risk driver. Another example is the potential of equipment failure to lead to an ignition; indication of potential equipment failure will guide our inspection program scheduling.

Combined Mitigation Effectiveness

In this section, we address the effectiveness of mitigation activities to rebuild the distribution grid.

A central element of PG&E’s wildfire risk mitigation strategy is to deploy mitigations—activities designed to reduce ignition risk by changing how PG&E’s grid is constructed and operated—in combination to increase their effectiveness. Mitigations are also combined with ignition risk control activities that are designed to maintain the current baseline risk level.

Activities such as on-going asset inspections and vegetation management are risk control activities. We implement these routine controls across our entire system, and, by their nature, they are used with mitigations such as covered conductor and protective device and equipment settings. For example, PG&E routinely conducts on-going VM in areas where we have installed covered conductor and implemented EPSS. While mitigations in combination can be more effective at reducing ignition risk, and PG&E can calculate the increases in mitigation effectiveness, mitigations and controls used together are complimentary. Use of a control does not impact mitigation effectiveness.

PG&E has evaluated the effectiveness of the distribution wildfire mitigations that we most often deploy and compared the effectiveness of mitigations used alone and in combination. Our evaluation is based on a detailed economic analysis for each mitigation considering the long-term benefits compared to the costs over the life of the asset. Table PG&E-6.1.3-1 shows the results of that analysis.

TABLE PG&E-6.1.3-1:
MITIGATION EFFECTIVENESS ALONE AND IN COMBINATION

Line No.	System Hardening Mitigation(s)	Blended Average Effectiveness[(a)]
1	Undergrounding All[(b)]	99%
2	Undergrounding Primary[(c)] Distribution Lines	98%
3	Line Removal with Remote Grid	98%
4	Covered Conductor + EPSS + PSPS[(d)]	97%
5	Covered Conductor + EPSS + DCD	79%
6	Covered Conductor	67%

(a) This effectiveness evaluation is based on an assessment of each mitigation’s prevention of an ignition from active faults of known cause on overhead assets. Company initiated outages, including PSPS outages, outages of Unknown cause, as well as outages on existing underground assets are not applicable to this study and are excluded from calculation results as “N/A.”

(b) Includes distribution primary, secondary, and services line(s).

(c) Includes distribution secondary and services parallel to targeted primary line(s).

(d) The combined “Overhead with EPSS and PSPS” effectiveness differs from others in the table as it is the result of two independent studies. The first study yields PSPS effectiveness alone to be approximately 84% effective at mitigating wildfire risk. Subsequently, the combined effectiveness of approximately 79 percent for “Overhead with EPSS” is applied on top of the PSPS reduction, resulting in: Mitigation Effectiveness = 84% + (100%-84%) * 79% = 97%.

- Distribution Undergrounding: Undergrounding is the most effective way to permanently reduce wildfire risk and significantly reduces outage program risk. Undergrounding primary distribution lines is approximately 98 percent effective at mitigating wildfire risk. If we underground all the way to the meter and include the service drop, the risk reduction is approximately 99 percent.

- Covered Conductor + EPSS + PSPS: The combination of covered conductor, EPSS and PSPS is approximately 97 percent effective at reducing ignition risk. The combined use of covered conductor, EPSS, and PSPS introduces a high likelihood of system outage risk and is disruptive to our customers.

- Line Removal with Remote Grid: Line removal is 100 percent effective at reducing wildfire risk in areas previously served by that line. When combined with a remote grid to serve the customers previously served by the removed line, the approximate effectiveness of the mitigation is 98 percent. This is a reasonable solution in a limited number of situations where the number of customers previously served does not merit the continued maintenance of the line.

- Covered Conductor + EPSS + DCD: The combination of covered conductor, EPSS and DCD is approximately 79 percent effective at reducing ignition risk. DCD can improve the ability to detect and isolate high impedance faults (conditions where downed conductor does not draw a large enough fault current that a protective device can reliably sense and trip the circuit offline). While more effective in combination than covered conductor alone, the combination introduces a high likelihood of system outage risk.

- Distribution Covered Conductor Installation: Covered conductor installation is approximately 67 percent effective at reducing ignition risk. Covered conductor is a preferred mitigation in areas where undergrounding is infeasible.

Estimated Implementation Costs for Mitigation Combinations:

PG&E estimates that the average cost for primary distribution undergrounding is approximately $3.0 million per mile and the average cost to install covered conductor is approximately $1.0 million per mile.

While undergrounding is PG&E's preferred solution for mitigating ignition risk in the highest risk areas, we recognize that undergrounding takes longer to execute than overhead hardening and is a more costly investment in the short term. In the highest risk locations, the long-term benefits of undergrounding including greater wildfire risk reduction, reliability improvement and operational cost avoidance (e.g., less vegetation management) make it the best long-term investment for customers and communities. Undergrounding provides benefits beyond just wildfire weather scenarios such as winter storms, atmospheric rivers, and extreme heat.

Covered conductor can generally be installed more quickly and costs less than undergrounding, but it does not protect against tree strike risk or fully address the reliability risk. Given increasing instances of extreme weather and volatility, the stress on vegetation around our assets is only expected to get worse. Therefore, undergrounding, where feasible, is the best alternative where tree strike risk is high.

Risk Attitude, Risk Tolerance, Uncertainty

PG&E's overall approach is focused on reducing the potential for catastrophic risk events. Central to this approach is the ability to quantify in its risk assessments the possibility of Tail Risk events, defined as low frequency, high consequence events. PG&E primarily achieves this in its risk modeling by adopting a risk-averse Risk Attitude—also known as Risk Scaling-Function. With the CBA, risk and risk reduction are both expressed in dollars. PG&E adopts a market-based approach to developing Risk Scaling Functions, such that the function(s):

1) Does not lower the expected monetized value of the attribute levels (i.e., not risk-seeking); and

2) Notwithstanding the above, results in values consistent with prices and/or estimates from risk transfer markets, and/or public policy towards risk transfer, to the extent such pricing is applicable and available.

PG&E's approach, at its core, is to use available, objective data to determine the Risk-scaling function(s). Risk premiums from insurance and capital markets meet these criteria. These market prices encode preferences. As such, they can be used to develop empirically based Risk-Scaling Functions that will be more insightful and representative than any approach considered to date.

The market-based approach creates consistency and alignment. The CPUC already oversees PG&E's insurance and capital markets activities. Therefore, creating a tie between the RDF and insurance and capital markets provides consistent and complementary policies and decisions. The CPUC and utilities can look to the markets to assist in ascertaining the value of mitigations (i.e., the efficient allocation of capital). As mitigation programs are implemented, the amount of risk is reduced, which should reduce the premiums demanded by insurers and other market participants. Market theory tells us that the prices obtained from a perfect market maximize value to society. Of course, no market is perfectly competitive, complete, or truly representative of societal preferences, but there are established practices that can be employed within the market-based approach to account for shortcomings while still preserving its function of communicating societal values. Hence, Risk-Scaling Functions developed to be consistent with market prices would represent societal risk preferences, not those of the utility.

In summary, PG&E's objective is to use available market data to determine the fair value of risk and mitigations. Incorporating market data, via the Risk-Scaling Function, does not compel ratepayers to purchase insurance or other risk transfer policies. PG&E's insurance activities are already under the oversight of the CPUC and reviewed in the GRC; nothing here interferes with or impacts PG&E's existing insurance program and its oversight. The use of market information does not compel ratepayers to fund mitigations. Markets are often used to determine the fair value of goods and services, but whether one should obtain the said goods or services is dependent on individual circumstances. Hence, market data (from insurance and other risk transfer markets) can be used, in part, to determine the value of mitigations, and whether to fund such programs is part of a GRC, and should include budget considerations, overall priorities, risk tolerance and other factors.[45]

The Risk-Scaling Function is a bedrock component of PG&E's risk modeling, and is applied methodically across all risks, including PSPS and EPSS. Using the market-based approach above, separate Risk-Scaling Functions for reliability and safety are developed,[46] which are then applied to the consequence distribution of PSPS and EPSS events to arrive at (Risk-Adjusted) CoRE values, per Row 24 of the RDF.[47] Similarly, the post-mitigation CoRE values for PSPS and EPSS are determined by applying the Risk-Scaling Functions to the post-mitigated consequence distributions. In

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45 PG&E 2024 RAMP Report (May 15, 2024), (PG&E-2), pp. 2-20 to 2-22.

46 PG&E 2024 RAMP Report (May 15, 2024), (PG&E-2), pp. 2-22 to 2-28.

47 D.22-12-027, Appendix A, Row 24, p. A-14.

its Report on PG&E's 2024 RAMP Application, the CPUC SPD evaluated PG&E's Risk-Averse Risk Scaling Function and found that it was valid.[48]

As noted in our RAMP, Risk Tolerance is a key area for continued development and maturity. The CPUC is actively exploring Risk Tolerance proposals and methodologies in Phase 4 of the Risk OIR. In the meantime, PG&E is adopting an approach towards Risk Tolerance which reemphasizes that safety remains PG&E's top priority.[49]

6.1.3.2 Activity Prioritization

The electrical corporation must seek to implement the best integrated portfolio of activities using its project prioritization framework to meet its plan objectives, optimize its resources, and maximize risk reduction. Objectives may be based on quantified risk assessment results (see *Section 5**), or other values prioritized by the electrical corporation or broader stakeholder groups (e.g., Tribal interests, environmental protection, public perception, resilience, cost). The electrical corporation must do the following:*

- *Evaluate its potential activities. This evaluation will yield a prioritized list of activities. The objective is for the electrical corporation to identify the preferable activities for specific geographical areas. (Comparable to Risk Based Decision-making Framework, rows 12 and 26);[FN]*
- *Identify the best activities for all geographical areas at a location-specific level to create a portfolio of projects expected to provide maximal benefits within known limitations and constraints. (Comparable to Risk Based Decision-making Framework, rows 12 and 29).[FN] Explain when subject matter expertise is used as a part of activity selection, including the process used by SMEs to provide their judgement;*
- *Explain how the electrical corporation is optimizing its resources to maximize risk reduction. Describe how the proposed activities are an efficient use of electrical corporation resources and focus on achieving the greatest risk reduction with the most efficient use of funds and workforce resources; and*
- *Discuss the interrelationships between different activities, in terms of how activities influence and impact implementation and respective effectiveness for risk reduction, and how the electrical corporation evaluates trade-offs between activities.*
- *Describe how grid needs, including future projected needs, (e.g., load capacity, peak demand, system flexibility)[FN] influence activity prioritization.*

The electrical corporation must describe how it prioritizes activities to reduce both wildfire and PSPS risk. This discussion must include the following:

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48 SPD Evaluation Report on PG&E 2024 RAMP, A.24-05-008 (Nov. 8, 2024), p. 3.

49 PG&E 2024 RAMP Report (May 15, 2024), (PG&E-1) pp. 1-13 to 1-14.

- *A high-level schematic showing the procedures and evaluation criteria used to evaluate potential activities. At a minimum, the schematic must demonstrate the roles of quantitative risk assessment, resource allocation, evaluation of other plan objectives (e.g., cost, timing) identified by the electrical corporation, and SME judgment. Where specific local factors, which vary across the service territory, are considered in the decision-making process (e.g., the primary risk driver in a region is legacy equipment), they must be indicated in the schematic. The electrical corporation must explain why those local conditions are part of the decision process (i.e., there should not be simply one box in the schematic that is labeled "local conditions," which is then connected to the rest of the process); and*

- *Summary description (no more than five pages) of the procedures and evaluation criteria for prioritizing activities, including the three minimum requirements listed above in this section.*

PG&E prioritizes wildfire mitigation activities using the structured framework described in Section 6.1.3.1 above to maximize risk reduction while optimizing resource allocation. Most System Resilience work is included in a multi-year work plan, which was prepared prior to this WMP submission. PG&E annually reevaluates the performance of its wildfire mitigation activities. As part of this process, PG&E reevaluates its HFTD/HFRA annually, and, if there is any change, implements mitigations in any new/expanded areas. We then look at our highest risk circuit segments to determine where to target the work included in our multi-year plan. This iterative process results in some work being delayed and other work moved up to prioritize the highest risks within the available funding. This consistent, forward-looking approach helps ensure capital projects are planned and executed efficiently and affordably.

PG&E considers both local and systemic geographic areas informed by PG&E's operational and planning risk models to plan where to execute its wildfire mitigations.

Distribution

- *Geographic Area 1: The top-risk areas based on the wildfire risk model (HFTD/HFRA).*

- *Geographic Area 2: The remaining risk areas based on the wildfire risk model (remaining HFTD/HFRA areas).*

- *Geographic Area 3: Non-HFTD/HFRA.*

Transmission

- Geographic Area 1: HFTD/HFRA.

- *Geographic Area 2*: Non-HFTD/HFRA.

Table PG&E-6.1.3.2-1 identifies key mitigations by geographic area for Distribution and Table PG&E-6.1.3.2-2 identifies key mitigations by geographic area for Transmission.

**TABLE PG&E-6.1.3.2-1:
DISTRIBUTION RISK AREAS**

Mitigation	Geographic Area 1: Top Risk Areas based on Wildfire Risk Models (HFTD/HFRA)	Geographic Area 2: Remaining Risk Areas based on Wildfire Risk Models (HFTD/HFRA)	Geographic Area 3: Non-HFTD/HFRA
Comprehensive Monitoring and Data Collection			
Weather Stations	X	X	X
Wildfire Cameras	X	X	
Asset Inspections	X	X	X
Vegetation Inspections	X	X	X
Operational Mitigation Activities			
PSPS	X	X	X
EPSS	X	X	
Equipment Maintenance and Repair, Includes Pole Replacement and Reinforcement	X	X	X
Pole Clearing	X	X	X
Substation Defensible Space	X	X	
Resiliency Mitigation Activities			
Undergrounding	X		
Covered Conductor	X	X	
Distribution Line Removal	X	X	
HFTD/HFRA Open Tag Reduction – Distribution (Backlog)	X	X	

TABLE PG&E-6.1.3.2-2:
TRANSMISSION RISK AREAS

Mitigation	Geographic Area 1: (HFTD/HFRA)	Geographic Area 2: (Non-HFTD/HFRA)
Comprehensive Monitoring and Data Collection		
Weather Stations	X	X
Wildfire Cameras	X	
Asset Inspections	X	X
Vegetation Inspections	X	X
Operational Mitigation Activities		
PSPS	X	X
EPSS	X	
Equipment Maintenance and Repair, Includes Pole Replacement and Reinforcement	X	X
Utility Defensible Space (Pole/Structure Clearing)	X	
Integrated Vegetation Management	X	X
Substation Defensible Space	X	
Resiliency Mitigation Activities		
Conductor Segment Replacement	X	
Line Removal (Transmission)	X	
Shunt Splice Installation	X	

Resource Optimization and Risk Reduction

PG&E optimizes its available resources by analyzing and balancing multiple factors such as risk reduction values, geographic considerations, feasibility constraints, available construction resources, compliance requirements, and authorized funding. Emergency events, such as winter storms and emergency operations often require significant adjustments to the work plan due to sudden changes in resource availability. For these reasons, resource planning, including resource optimization, is an iterative process.

Trade-Offs Between Activities

In the simplest terms, implementation of permanent mitigations reduces, or in some cases eliminates, the need for some operational mitigations. For example, undergrounding overhead circuits in HFRAs greatly reduces the need for routine VM, while providing significant long-term wildfire risk reduction.

Overhead system hardening combined with operational mitigations EPSS and PSPS has a high-risk reduction benefit that is roughly comparable to that of undergrounding without these operational mitigations. PG&E continues to prefer undergrounding on high-risk circuits where feasible for several reasons. Underground is permanent risk reduction that does not have the negative reliability impacts from PSPS and EPSS. Underground facilities are less likely to be damaged during winter storms by high winds and vegetation falling into lines damaging the facilities or other contact with the lines from third parties. Over time, undergrounding also has lower operations and maintenance expenses.

PG&E implements PSPS events as a mitigation of last resort to reduce the potential for catastrophic wildfires during extreme weather events that could lead to wildfire. De-energization in a PSPS event has negative impacts to customers both due to the loss of power and potential indirect safety impacts resulting from long duration outages. PG&E represents wildfire as a risk on its Risk Register that includes the use of, as well as the negative impacts from PSPS and EPSS. To represent the trade-off of PSPS events and wildfire risk, PG&E assesses the effectiveness of a PSPS event as a form of wildfire mitigation and offsets the risk reduction benefits by these PSPS risks.

Figure PG&E-6.1.3.2-1 below is a chart that depicts wildfire risk with EPSS and PSPS trade-offs. This waterfall chart can be explained by the following definitions:

- Wildfire (pre-EPSS/PSPS): The inherent wildfire risk based on the data from 2017 to 2024, absent of the use of PSPS and EPSS operational mitigations. This captures ignitions that would occur if EPSS and PSPS ignitions were not deployed. This represents the inherent risk of PSPS on the system; the risk that permanent system resilient mitigations would help permanently drive down.

- Wildfire Mitigation (EPSS/PSPS): The wildfire risk reduction benefits that EPSS and PSPS operational mitigations provide.

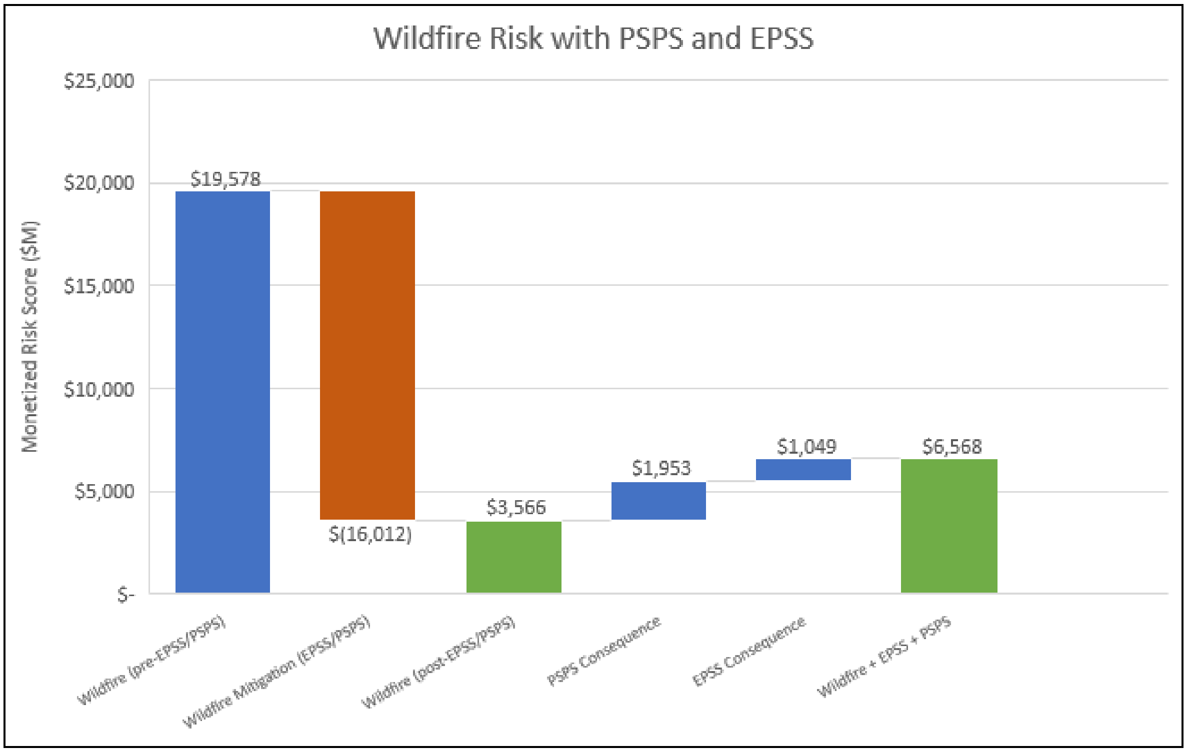
- Wildfire (post-EPSS/PSPS): The residual wildfire risk after utilizing EPSS and PSPS. This figure represents a substantially lower risk that PG&E and its customers bear, however, is not permanent.

- PSPS Consequence: The customer impact of PSPS. PG&E performs a lookback against historical weather events with its current PSPS protocols to examine the number of PSPS events, the customer scope, and the duration of de-energization given such weather events. Based on the Customer Minutes Interrupted (CMI), PG&E calculates the reliability impact, as well as the indirect safety impact of a long duration outage, in the form of a risk score.

- EPSS Consequence: The customer impact of EPSS. PG&E performs a lookback against historical outages with its current EPSS activation protocols to examine the number of outages that, if they occurred at the present time, would become an EPSS outage. In general, the size of the outage in the form of CMI is expected to be larger and would not exist if not for the use of EPSS. PG&E calculates the reliability impact, as well as the indirect safety impact of a long duration outage, in the form of a risk score.

- Wildfire + EPSS + PSPS: This represents the net impact of wildfire with the implementation of EPSS and PSPS, net of the negative impact of EPSS and PSPS consequence.

FIGURE PG&E-6.1.3.2-1:
2026 YEAR BASELINE
(WITH AND WITHOUT OPERATIONAL MITIGATION)



Note: A similar version of this figure was included in PG&E's 2024 RAMP (PG&E-4), Chapter 1, Figure 1-2. However, this figure has since been updated to include data through EOY 2024 and represents system-wide wildfire risk.

The analysis above demonstrates that program level trade-offs between wildfire mitigation and PSPS and EPSS reliability impacts are reasonable. Recognizing that no single model can perfectly quantify all risks with the electrical system, PG&E uses multiple models to review and prioritize wildfire mitigation measures. For many of the mitigation programs, wildfire risk is the primary driver of prioritization. This is true of our inspections risk-informed approach, the backlog tag strategy, and a portion of the VM activities.

PG&E is building new models to comply with the requirements of Senate Bill 884 to prepare an Electrical Undergrounding Plan. One specific requirement is the prioritization of Overall Utility Risk: a combined measure of Ignition Risk and Outage Program Risk that measures the total risk of wildfires and Outage Program Events related to wildfire risks. PG&E believes that PSPS and EPSS reliability risks are key components of this Outage Program Risk which can be calculated at the circuit segment level to provide a quantitative guide for workplan development. Strict rank order or strict Risk Buydown does not always allow for the most efficient execution of work, as it disregards the operational considerations of work execution. One such example is the performance of maintenance and inspection activities in the same area. This allows for operational efficiency as opposed to forcing workers to travel to geographically disparate areas simply to follow a strict rank order.

The rank order for mitigation selection can vary due to several factors. For example, prioritizing our open tag backlog uses a risk spend efficiency approach to aid in reducing the risk from backlog tags as quickly as possible. This allows for the efficient bundling of work for execution. On the other hand, Asset Inspection considers both WFC and wildfire risk when determining how frequently to inspect assets within the HFTD as this is the most appropriate way to perform the work.

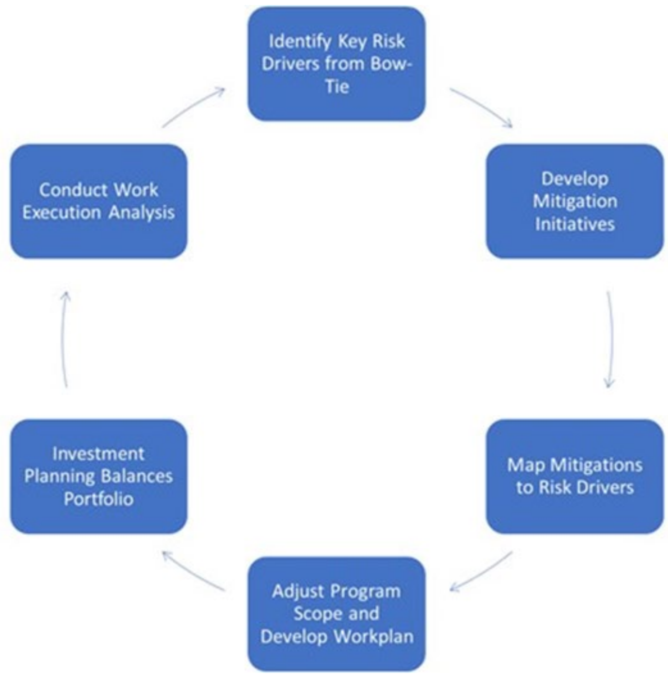
Model applications for the various mitigations also drive differences in the rank order. Vegetation work uses the vegetation model, whereas system hardening and undergrounding use a composite model, inclusive of all risk drivers. This approach means that a particular circuit segment can be ranked differently based on the model that is applied to it. A universal model application for all mitigations would not account for the most probable risk drivers for a given circuit segment.

Considerations for Future, Expected Grid Needs

PG&E's Integrated Grid Planning team facilitates incorporation of additional design considerations into the project scoping process for resiliency projects, including future grid needs. Through this process, PG&E may add scope to resiliency projects to address expected, future load capacity, peak demand, system flexibility, or other secondary design criteria.

Figure PG&E-6.1.3.2-2 below describes PG&E's process for identifying risk drivers, developing mitigation programs aligned to those drivers, evaluating and adjusting program scope and execution plans, balancing the overall investment portfolio, and conducting execution work analysis. This schematic describes iterative procedures and criteria we employ for selecting and balancing our mitigation portfolio.

FIGURE PG&E-6.1.3.2-2:
DEVELOPING THE BALANCED MITIGATION PORTFOLIO



6.1.3.3 Activity Scheduling

The electrical corporation must report on its schedule for implementing its portfolio of activities. The electrical corporation must describe its preliminary schedules for each activity and its iterative processes for modifying activities (Section 6.1.3.1).

Activities may require several years to implement. For example, relocating transmission or distribution capabilities from overhead to underground may require substantial time and resources. Since activities are undertaken in high-risk regions, the electrical corporation may need interim activities to mitigate risk while working to implement long-term strategies. Some examples of interim activities include more frequent inspections, fire detection and monitoring activities, and PSPS usage. If the electrical corporation's activities require more than one year to implement,[50] *the electrical corporation must evaluate the need for interim activities, as discussed in Section 6.2.2.*

In its WMP submission, the electrical corporation must provide a summary description of the procedures it uses in developing and deploying activities. This discussion must include the following:

- *How the electrical corporation schedules activities;*

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50 *Meaning that it will take the electrical corporation more than one year to electrify or implement a given activity from the time it determines it will utilize that activity in a given location.*

- *How the electrical corporation incorporates the amount of time it takes to implement the activities when determining initiative effectiveness and prioritization. This must include evaluations of cumulative risk exposure while the initiative is being implemented, as well as interim activities;*
- *How the electrical corporation evaluates whether an interim initiative activity is needed and, if so, how an interim activity is selected (see Section 6.2.2);*
- *How the electrical corporation monitors its progress toward its targets within known limitations and constraints. This should include descriptions of mechanisms for detecting when an activity is off track and for bringing it back on track; and*
- *How the electrical corporation measures the effectiveness of activities (e.g., tracking the number of PEDS de-energizations that had the potential to ignite a wildfire due to observed damage/contact prior to re-energization). The mitigation category sections of these Guidelines (Sections 8-12) include specific requirements for each activity.*

Overview of PG&E's Scheduling Approach

System Resilience projects, such as undergrounding and overhead system hardening, are selected using the risk-informed prioritization process described in Section 6.1.3.2 and added to the multi-year work plan. System Resilience programs require multiple years to implement, even as individual System Resilience projects continue to be scheduled and completed each year. To mitigate and control wildfire risk during the implementation phase of System Resilience projects, PG&E utilizes Operational Mitigations, such as PSPS and EPSS. Other Operational Mitigation work, such as VM, is typically scheduled on a recurring, annual basis with exact timing driven by logistical, operational, and compliance considerations. Asset inspections within the HFTD/HFRA are scheduled to occur as soon as feasible after the end of the seasonal winter storm period (historically March or April) to enable PG&E to mitigate newly identified issues before the traditional wildfire season begins (historically June or July).

In parallel, PG&E's Comprehensive Monitoring and Data Collection framework continuously informs and influences mitigation activity scheduling. The proposed scope and schedule for newly identified mitigations are brought to the Wildfire Risk Governance Steering Committee before they are added to the multi-year work plan.

Monitoring Progress and Course Correction Mechanisms

PG&E employees responsible for executing mitigation activities hold weekly schedule validation meetings to confirm that work is meeting the approved program schedule. Topics of these meetings include status updates, schedule changes, and any issues and risks to schedules. Leaders follow the Lean Operating System and hold daily, weekly, and monthly operating reviews to assess performance against the overall work plan scope, schedule, and budget. The Lean Operating System provides for: (a) consistent program monitoring through visual management that shows how we are performing against safety, customer, delivery, and quality; (b) operating reviews focused on identifying and addressing issues and barriers to getting the right work done; (c) resolving issues and negative trends as soon as they are identified; and (d) standardizing effective work processes and best practices.

Through the Wildfire Weekly Operating Review, PG&E also monitors the progress of our wildfire mitigation activities and performance against metrics. The Wildfire Weekly Operating Review includes formal tracking programs for these activities. Emergency Operations (EO) also reports on the status of its risks and the performance of its risk response programs to the Risk and Compliance Committee and the WRGSC. Based on the performance of the risk programs, PG&E may accelerate or adjust our responses to better manage the risk.

Measuring Effectiveness

PG&E will evaluate the effectiveness of mitigation activities described in the 2026-2028 WMP by using the performance metrics included in the Quarterly Data Report. In addition, PG&E proposes to use a performance metric for CPUC-Reportable Fire Ignition Rates (Weather Normalized) as set forth in Section 3.5.

Preliminary Schedules

Figures PG&E-6.1.3.3-1, PG&E-6.1.3.3-2, and PG&E-6.1.3.3-3 below show approximate dates wildfire mitigations were installed from 2020-2024 and the currently-estimated schedule for 2025-2028. The three figures combined show how we have deployed and will continue to deploy our mitigation portfolios to monitor our system, provide interim risk mitigation, and increase resiliency. The initiative percent complete indicated is an estimate as of February 2025. The actual work completed will vary over time.

FIGURE PG&E-6.1.3.3-1:
SYSTEM RESILIENCE MITIGATIONS
IMPLEMENTATION SCHEDULE

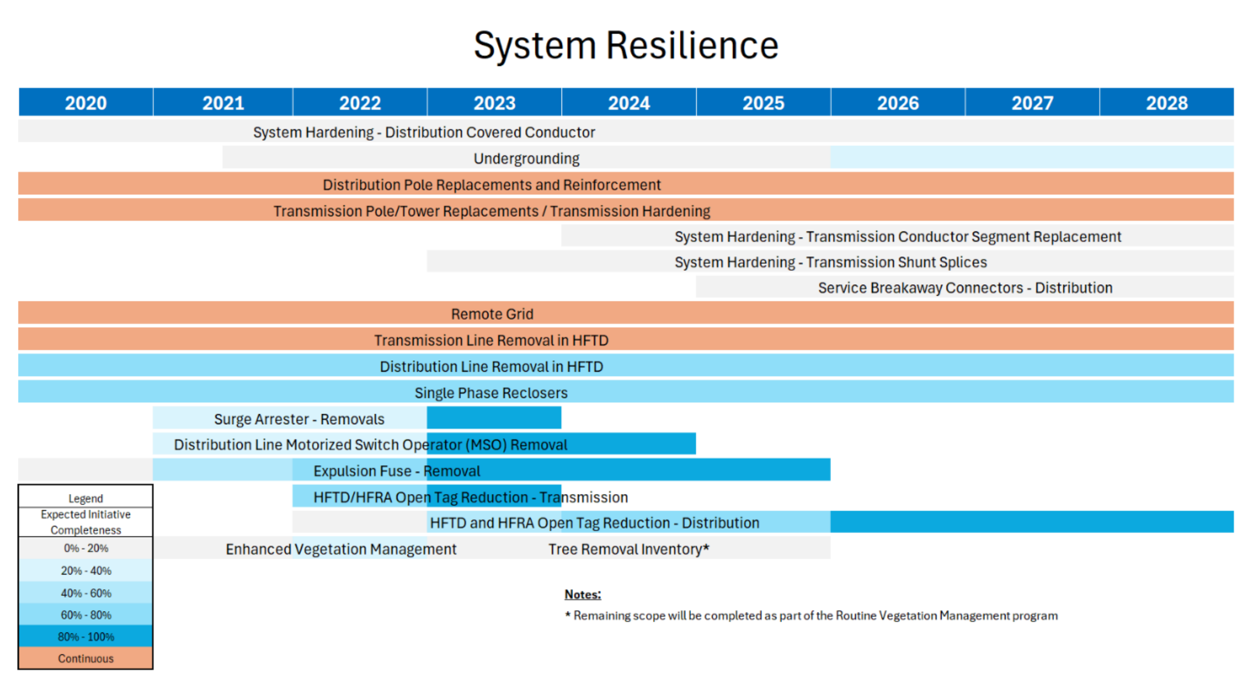


FIGURE PG&E-6.1.3.3-2:
OPERATIONAL MITIGATIONS
IMPLEMENTATION SCHEDULE

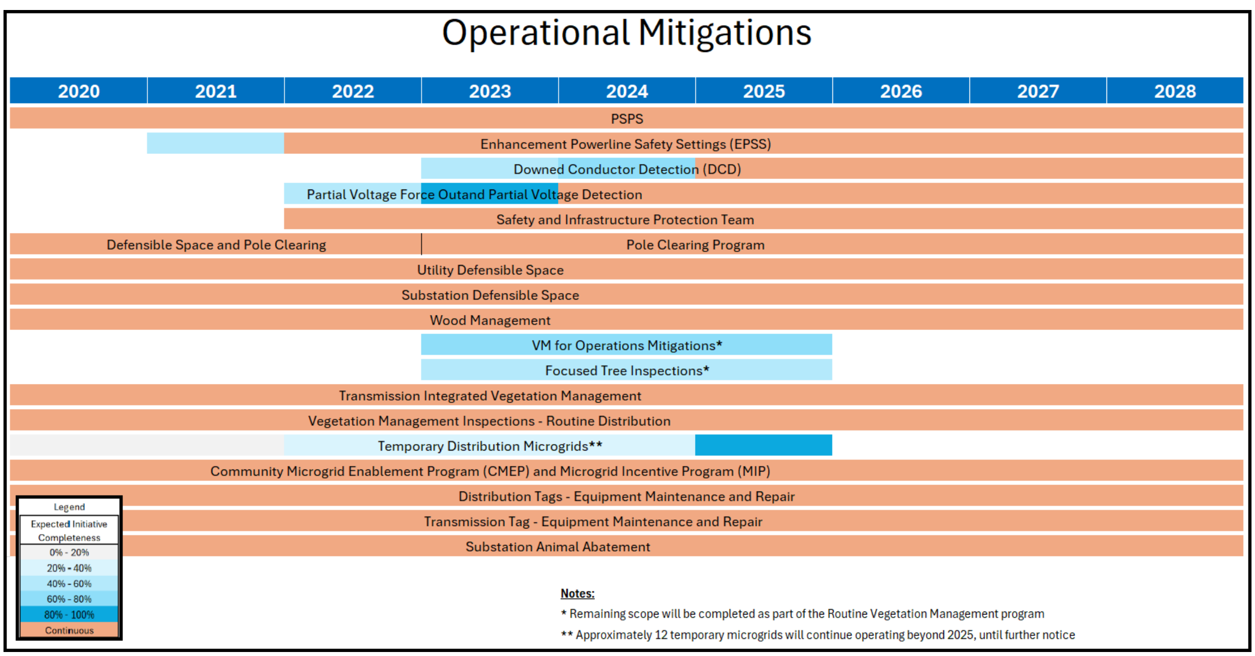
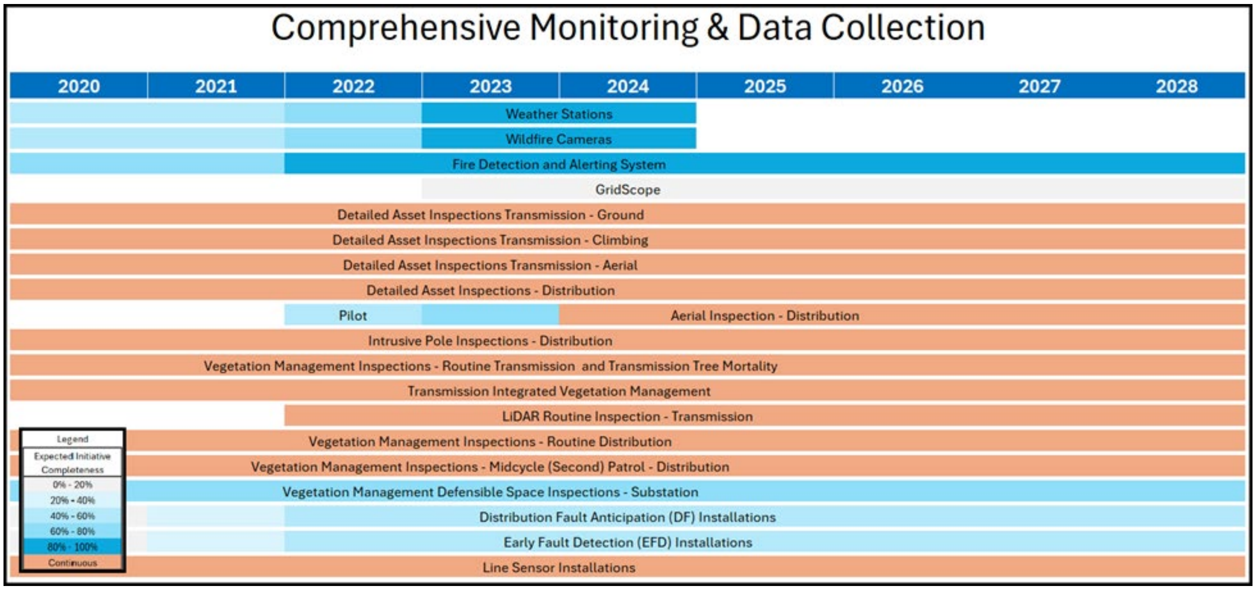


FIGURE PG&E-6.1.3.3-3:
COMPREHENSIVE MONITORING AND DATA COLLECTION IMPLEMENTATION SCHEDULE



6.1.3.4 Key Stakeholders for Decision Making

In this section, the electrical corporation must identify all key stakeholder groups that are part of the decision-making process for developing and prioritizing activities. Table 6-2 provides an example of the required information and format. At a minimum, the electrical corporation must do the following:

- *Identify each key stakeholder group (e.g., electrical corporation executive leadership, the public, state/county/Tribal Nation public safety partners);*
- *Identify the decision-making role of each stakeholder group (e.g., decision maker, consulted, informed);*
- *Identify method of engagement (e.g., meeting, workshop, written comments);*
- *Identify engagement methods that describe how it communicates decisions to key stakeholders;*
- *Identify what type of activity (i.e., system hardening, vegetation management) the stakeholder is engaged with; and*
- *Identify the level of engagement (i.e., local, tribal, federal) for activities for any projects that are within stakeholder jurisdictions.*

As noted above, the WRGSC makes decisions about developing and prioritizing mitigation initiatives. The WRGSC is responsible for reviewing plans and considering the risk reduction from the proposed mitigations, the scope of work, interaction among mitigations and controls, time to implement the initiative, and potential constraints. After a detailed review, the WRGSC decides which mitigations to pursue and the scope of the program. The WRGSC-approved plans are an input into the annual investment plan. Wildfire Risk Management; Asset Strategy; Engineering and Standards; Ignitions Investigations; VM; Investment Planning; Major Projects; EO; and Asset Knowledge and Management all provide input to the annual investment plans. The WRGSC meets bi-weekly and has additional meetings as needed.

The WRGSC Charter is included below as Figure PG&E-6.1.3.4-1:

FIGURE PG&E-6.1.3.4-1:
WILDFIRE RISK GOVERNANCE STEERING COMMITTEE CHARTER

Wildfire Risk Governance Steering Committee Charter

Purpose:

1. Drive decisions that prevent catastrophic wildfires, mitigate wildfire risk, and reduce customer impact. 2. Drive decisions to ensure PG&E obtains its Safety Certificate in a timely manner

Attendees:

Voting Members:
- Chair: Chief Risk Officer and Senior Vice President, Ethics & Compliance
- SVP, Wildfire & Emergency Operations [backup for Chair]
- SVP, Electric Engineering
- SVP, Electric Operations
- SVP, Local Customer Engagement
- VP, Chief Audit Officer
- VP, Vegetation Management
- Sr. Director, Data, Analytic & Insights

Invited Leadership:
- VP, Electric Engineering Asset & Regulatory
- VP, Transmission & Substation Operations
- VP, North Coast Region
- VP, System Inspections
- VP, Electric Distribution Operations
- VP, Regulatory Affairs
- VP, Enterprise and Operational Risk
- VP, North Valley & Sierra Region
- Sr. Director, Wildfire Risk Management
- Sr. Director, Internal Audit
- Sr. Director, Asset Strategy

Facilitators: Wildfire Mitigation PMO team | Guests by invitation: *Team members involved in developing the meeting topics are invited to attend the meeting to understand the decision-making process and cascade the decision to all affected teams.*

How decisions are made:

- A quorum of 50% of voting members must be in attendance
- A voting member may delegate to a Vice President or Sr. Director level delegate if unable to attend.
- Approval requires a simple majority vote (>50%) of voting committee members. Abstentions are excluded from the vote.
- In the event of a tie vote, the Committee Chair or backup for Chair may break the tie
- When a quorum cannot be reached, the Committee Chair has ultimate decision-making authority and may opt to approve urgent topics in the absence of a quorum. This authority cannot be delegated.
- If the Committee Chair is not in attendance, voting will occur among the voting members in attendance. Votes will be solicited from the non-present members to meet quorum via email. Decisions are recorded once a majority of the voting members have voted.

Meeting Logistics:

- ***Frequency/Duration:*** Scheduled every other week on Thursday, Ad Hoc as requested
- Pre-read materials will be sent to meeting attendees 1 week before the scheduled meeting.
- Action items included in the meeting material and posted weekly at the Wildfire Risk Command Center (WRCC)
- Action items greater than 30 days will be converted to a CAP to allow for accurate tracking.
- Meeting decisions are documented following the meeting and sent to attendees. *Recipients are expected to cascade decisions to the impacted organizations.*
- Final materials that include decisions, action items and incorporating requested edits are sent to attendees in the week following the meeting.
- ***Agenda:*** Director, Wildfire Mitigation PMO to approve final agenda

In Scope

Review and approval of:
- Work plan reprioritization impacting risk reduction within the commitment timeframe
- Work plan changes impacting compliance with external commitments
- New risk models, refreshed input data on existing risk models, or significant changes to risk models
- Translation of risk model to risk-informed work plan for execution
- Resolutions to escalated action items flagged for committee approval
- Self-report corrective action plans relating to the WMP
- Decisions regarding Wildfire Strategy & Plans made by the CEO and COO will be reviewed as informs (original decision materials will be reviewed by Legal and included in the WRGSC appendix)
- WRGSC will ensure all decisions are aligned with financial and regulatory commitments utilizing the Plan Delivery Center (PDC) process. Decision topics that trips a PDC related threshold, will be presented as informs at the WRGSC and will receive PDC approval prior to final WRGSC approval.

Out of Scope*

- Inform topics and regular reporting of work completed and quality results
- Work pace changes not impacting delivery of external commitments or risk profile
- Approval of efficiency initiatives addressing work execution barriers not impacting delivery of external commitments or risk reduction

**Regular reporting of work completion, quality results and trends will be conducted in the weekly Wildfire WOR*

PG&E also collaborates with external stakeholders such as CAL FIRE, Energy Safety, the CPUC, environmental agencies such as California Fish and Game and Regional Water Quality Boards, CAISO, other California electric utilities, California Fire Safe Councils, customers, Community Based Organizations, local communities, and government leaders. PG&E also interacts with customers through meetings and town-hall type events hosted by our Regional Vice Presidents (RVP). The RVPs participate in WRGSC meetings and have the opportunity to raise customer concerns or input, which also helps to inform our wildfire risk mitigation efforts.

We communicate decisions about our mitigation selection to key internal stakeholders through the WRGSC process. After evaluating the proposals, the WRGSC selects and approves an appropriate mitigation strategy. For proposals that are not initially approved, the WRGSC provides the team targeted guidance and teams may make additional future proposals.

Tables 11-5 and 11-7 in Appendix F provide more details regarding PG&E's engagement and collaboration with public safety partners, external stakeholders and tribal governments regarding its wildfire mitigation activities.

TABLE 6-2:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods	Activities	Level of Engagement for Activity
Public	Various public entities and customers	Senior Director, Customer Engagement	Consults and informs regarding various wildfire mitigation planning and execution efforts including customer resilience, outreach and education and notifications.	Regional Working Groups Joint IOU Statewide AFN Advisory Council Joint IOU AFN Collaborative Planning Team Joint IOU AFN Planning Team PG&E's People with Disabilities and Aging Advisory Council Wildfire Safety Webinars	Wildfire Mitigation Strategy and Activities	See Tables 11-5 and 11-7 (Appendix F)
Various fire agencies	Various – See Table 11-5 in Appendix F	PSS	Coordinates with local fire suppression agencies.	Phone conversations and in-person engagement. The PSS team engages external public safety partners on an on-going basis to provide wildfire and PSPS emergency preparedness information and response support. Engagements encompass a variety of outreach channels such as: first responder workshops; wildfire safety town halls; California Governor's Office of Emergency Services Mutual Aid Regional Advisory Council; general Regional Coordinator meetings; Quarterly Regional Working Group meetings; Community Wildfire Safety Program Advisory Committee meetings; professional group meetings; training/exercises/drills; and one-on-one delivery. Additionally, PSS team engagement follows California's Standardized Emergency Management System, the Federal Emergency Management Agency and the National Incident Management Systems when communicating through our respective county Office of Emergency Services channels when in-scope for a PSPS event or wildfire emergency posture.	Wildfire Mitigation Strategy and Activities	See Tables 11-5 and 11-7 (Appendix F)

TABLE 6-2:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS
(CONTINUED)

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods	Activities	Level of Engagement for Activity
Various Tribes	Various – See Table 11-7 in Appendix F	Corporate Sustainability Principal: Tribal	See Section 11.3.3.	Quarterly meetings in 2024 and e-mails, calls, newsletters, and in-person meetings as warranted.	Wildfire Mitigation Strategy and Activities	See Tables 11-5 and 11-7 (Appendix F)
Electrical Corporation SMEs	Public Safety Specialist (PSS)	Senior Director Electric Program Management (Safety and Infrastructure Protection Team (SIPT) and PSS)	Provide insight into local environmental conditions to support wildfire mitigation planning.	WRGSC	Wildfire Mitigation Strategy and Activities	Internal
Investment Planning	Director Electric Investment Planning	Director Electric Investment Planning	Facilitates the incorporation of wildfire risk mitigation program funding into PG&E's overall electric funding target allocation.	Enterprise Business Plan Deployment Process	Wildfire Mitigation Strategy and Activities	Internal
PG&E Executive Officer Team	Chief Risk Officer and Senior Vice President (SVP), Ethics and Compliance	Not Applicable	WRGSC-Chair Drives decisions to prevent catastrophic wildfires, mitigation wildfire risk and reduce customer impact. Also drives decisions to support PG&E's obtainment of its Safety Certificate. The scope of the WRGSC is in the charter included in Figure 6.1.3.4-1 above.	WRGSC Meetings	Wildfire Mitigation Strategy and Activities	Internal
Senior PG&E Leadership Team	SVP, Electric Operations	Not Applicable	WRGSC-Voting Member Drives decisions to help prevent catastrophic wildfires, mitigate wildfire risk and reduce customer impact. Also drives decisions to support PG&E's obtainment of its Safety Certificate. Provides feedback on constraints, operability, and ability to execute on potential mitigation plans.	WRGSC Meetings	Wildfire Mitigation Strategy and Activities	Internal
Senior PG&E Leadership Team	SVP, Electric Engineering	Not Applicable	WRGSC-Voting Member Drives decisions to help prevent catastrophic wildfires, mitigate wildfire risk and reduce customer impact. Also drives decisions to support PG&E's obtainment of its Safety Certificate. Provides feedback on the engineering and strategic objectives of potential mitigation plans, including the impacts to the investment planning portfolio.	WRGSC Meetings	Wildfire Mitigation Strategy and Activities	Internal

TABLE 6-2:
STAKEHOLDER ROLES AND RESPONSIBILITIES IN DECISION MAKING PROCESS
(CONTINUED)

Stakeholder	Stakeholder Point of Contact	Electrical Corporation Point of Contact	Stakeholder Role	Engagement Methods	Activities	Level of Engagement for Activity
Senior PG&E Leadership	SVP, Wildfire and Emergency Operations	Not Applicable	WRGSC-Voting Member Drives decisions to help prevent catastrophic wildfires, mitigate wildfire risk, and leads emergency response and operations. Also drives decisions to support PG&E's obtainment of its Safety Certificate. Provides guidance and direction on the overall WMP development and submission.	WRGSC Meetings	Wildfire Mitigation Strategy and Activities	Internal

Note: External stakeholder roles and responsibilities are not included in this table because the external stakeholders, the points of contact, roles, and engagement methods vary. We provide a list of external stakeholders in the narrative above.

Type of Activity – All Wildfire Mitigation Initiatives

Level of Engagement – Ensure internal alignment and support

6.2 Wildfire Mitigation Strategy

Each electrical corporation must provide an overview of its proposed wildfire mitigation strategies based on the evaluation process identified in Section 6.1.[51]

6.2.1 Anticipated Risk Reduction

In this section, the electrical corporation must present an overview of the expected risk reduction of its wildfire activities.

The electrical corporation must provide:

- *Projected overall risk reduction; and*
- *Projected risk reduction on highest-risk circuits over the 3-year WMP cycle.*

6.2.1.1 Projected Overall Risk Reduction

In this section, the electrical corporation must provide a figure showing the projected overall utility risk in its service territory as a function of time, assuming the electrical corporation meets the planned timeline for implementing the activities. The figure is expected to cover at least 10 years. If the electrical corporation proposes risk reduction strategies for a duration longer than 10 years, this figure must show that corresponding time frame.

In this section, PG&E describes our anticipated risk reduction resulting from our wildfire mitigation activities. We describe our projected overall risk reduction as a function of time for the 10-year period starting in 2023 (Figure 6-1) and the projected risk reduction on our highest-risk circuits over the 3-year WMP cycle (Table 6-4A).

This analysis represents the system-wide risk reduction driven by our system resilience and operational mitigation programs for the 3-year WMP cycle and the projected system-wide risk reduction for the remainder of the 10-year period. In Figure 6-1, PG&E provides two scenarios showing risk reduction from its risk mitigation activities with and without operational mitigation activities. The projected risk reduction includes both wildfire and outage program risk across PG&E's entire service territory.

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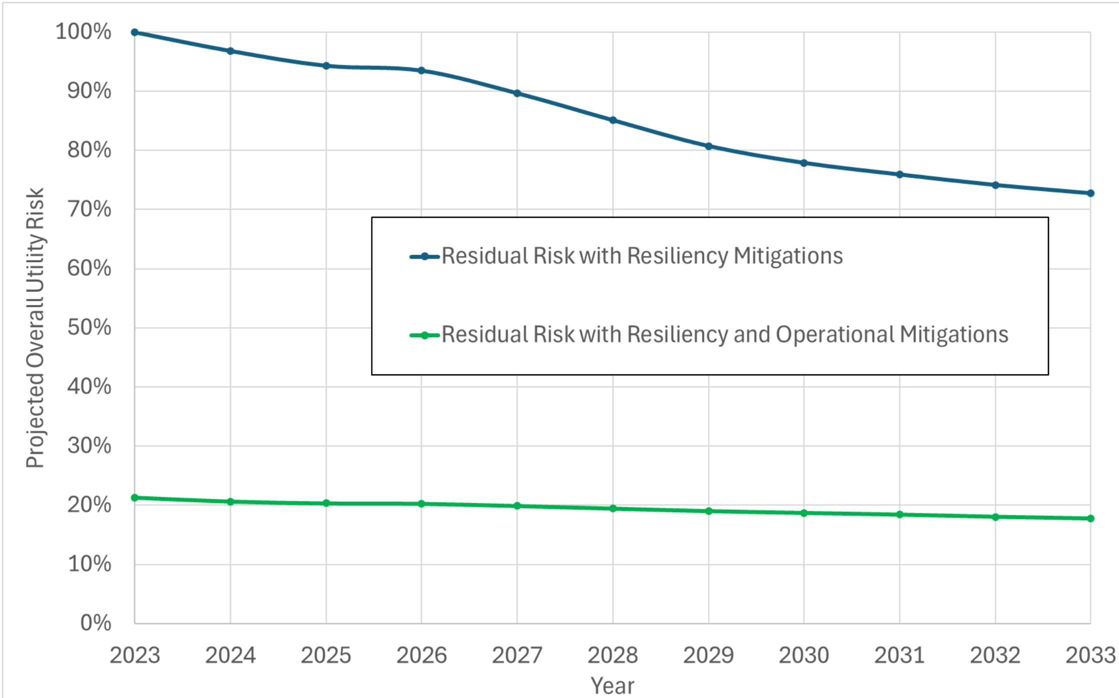
[51] *Pub. Util. Code § 8386(c)(3).*

FIGURE 6-1:
PROJECTED OVERALL SERVICE TERRITORY RISK



Note: Updated based on adjustments made to the overall utility risk for programs in response to Critical Issues RN-PGE-26-04, RN-PGE-26-05 and RN-PGE-26-10. See 2026-2028 WMP Revision Notice Response R0 for additional information.

6.2.1.2 Risk Impact of Activities

The electrical corporation must calculate the overall expected effectiveness for risk reduction of each of its activities. The overall expected effectiveness is the expected percentage for the average amount of risk reduced by the activity. This must be calculated for overall utility risk, being a summation for wildfire risk and outage program risk, as well as wildfire risk and outage program risk, respectively.

The electrical corporation must provide the cost benefit score,[52] *broken out by overall utility risk, wildfire risk, and outage program risk. The score should be calculated for the activity overall based on overall average activity effectiveness and average unit costs.*

The electrical corporation must calculate the expected % HFTD/HFRA[53] *covered for each of its initiative activity targets over the WMP cycle. The expected % HFTD/HFRA*

52 *"Cost benefit score" in this instance is the calculation performed by the electrical corporation to determine the cost effectiveness in comparison to risk reduction as it aligns with the current CPUC decision.*

53 *If an electrical corporation has identified areas outside of the HFTD to include within the HFRA, then this includes both areas. Otherwise, this would only include HFTD.*

covered is the percentage of HFTD and HFRA being worked on by the given activity from the first year of the Base plan to the last year of the Base plan. This could include the number of circuit miles or the number of assets. For example:

For covered conductor installations, the expected installations from January 1, 2026, through December 31, 2028 = 600 circuit miles

The total number of miles within the HFTD and HFRA = 4,250 circuit miles

The expected % HFRA covered for the covered conductor installations activity from 2026 to 2028 is:

$$\frac{\text{units of activity}}{\text{units within HFTD/HFRA}} \times 100$$

$$\frac{600}{4{,}250} \times 100 = 14.12\%$$

The electrical corporation must calculate the expected % risk reduction of each of its activity targets over the WMP cycle. The expected % risk reduction is the expected percentage risk reduction for the last day for Base WMP implementation compared to the first day for Base WMP implementation. For example:

For protective devices and sensitivity settings, the total risk on January 1, 2026 = 2.59 x 10^{-1}

After meeting its planned activity targets for protective devices and sensitivity settings, the total risk on December 31, 2028 = 1.29 ×10^{-1}

The expected x% risk reduction for the protective devices and sensitivity settings activity in 2026 is:

$$\frac{\text{risk before} - \text{risk after}}{\text{risk before}} \times 100$$

$$\frac{2.59 \times 10^{-1} - 1.29 \times 10^{-1}}{2.59 \times 10^{-1}} \times 100 = 50\%$$

The electrical corporation must discuss how it determined the total risk after implementation (the "risk after" component above). For instance, this could include estimating based on subject matter expertise, calculating based on historical observed reduction of ignitions, or using established understandings of effectiveness based on industry usage.

The expected % risk reduction numbers must be reported for each planned activity, when required, in the specific mitigation category sections of Sections 8-12 (see example tables in these Sections). Table 6-3 provides an example of a summary of reporting on the expected % risk reduction of activities.

The electrical corporation must also provide a step-by-step calculation showing how it derived the values provided below, similar to the examples shown above.

Table 6-3 below shows the risk impact of activities proposed in this WMP.

TABLE 6-3:
RISK IMPACT OF ACTIVITIES

Activity	Activity Section #	Activity - Effectiveness - Overall Risk	Activity - Effectiveness - Wildfire Risk	Activity - Effectiveness - Outage Program Risk	Cost-Benefit Score - Over all Risk[(d)]	Cost-Benefit Score - Wildfire Risk[(d)]	Cost-Benefit Score - Outage Program Risk[(d)]	% HFTD Covered	% HFTD/ HFRA Covered	Expected % Risk Reduction	Model Used to Calculate Risk Impact
Covered conductor installation[(a)]	8.2.1	62%	67%	23% [(f)]	19.9	19.2	0.7	2.7%	2.6%	2.8%	WDRM v4
Undergrounding of electric lines and/or equipment [(a)]	8.2.2	98%	98%	100%[(g)]	8.4	8.0	0.4	4.3%	4.3%	6.0%	WDRM v4
PSPS[()]	7	70%	95%	(59)%	28.9	48.6	(19.7)	100%	100%	NA	WDRM v4
EPSS[(c)]	8.2.8	45%	65%	(73)%	35.3	40.0	(4.7)	100%	100%	NA	WDRM v4
HFTD/HFRA distribution backlog tags	8.6.2	NA	14%	NA	NA	NA	NA	75%	75%	1.9%	WDRM v4
Pole clearing – Compliance [(d)]	9.4	NA	20%	NA	NA	NA	NA	3.8%%	3.8%	0.18%	WDRM v4
Pole clearing – Risk Reduction[(d)]	9.4	NA	20%	NA	NA	NA	NA	3.5%	3.8%	0.12%	WDRM v4
Distribution routine patrol[(h)]	9.2.1	NA	6%	NA	NA	NA	NA	100%	100%	2.4%	WDRM v4
Service drops/ breakaway connectors	8.2.10.6	NA	80%	NA	NA	NA	NA	0.6%	0.6%	0.02%	WDRM v4
Transmission shunt splice installation	8.4.9.2	NA	88%	NA	NA	NA	NA	NA	0.7%	0.2%	WTRM v2

TABLE 6-3:
RISK IMPACT OF ACTIVITIES
(CONTINUED)

Activity	Activity Section #	Activity - Effectiveness - Overall Risk	Activity - Effectiveness - Wildfire Risk	Activity - Effectiveness - Outage Program Risk	Cost-Benefit Score - Over all Risk(d)	Cost-Benefit Score - Wildfire Risk(d)	Cost-Benefit Score - Outage Program Risk(d)	% HFTD Covered	% HFTD/ HFRA Covered	Expected % Risk Reduction	Model Used to Calculate Risk Impact
Transmission conductor segment replacement	8.2.5.1	NA	75%	NA	NA	NA	NA	NA	0.4%	0.1%	WTRM v2

(a) In response to Critical Issues RN-PGE-26-04 and RN-PGE-05, Cost-Benefit Score - Overall, Cost-Benefit Score - Wildfire Risk, Cost-Benefit Score - Outage Program Risk, % HFTD Covered, %HFTD/HFRA Covered, and Expect % Risk Reduction data have been updated. See 2026-2028 WMP Revision Notice Response R0 for additional information.

(b) This figure represents catastrophic wildfire effectiveness

(c) This figure represents the effectiveness of EPSS at reducing ignitions under R3 and above FPI conditions

(d) In response to Critical Issue RN-PGE-26-10, Pole Clearing is split between Pole Clearing - Compliance and Pole Clearing - Risk Reduction. Percent of HFTD Covered, Percent of HFTD/HFRA Covered and Expected % Risk Reduction have been updated. See 2026-2028 WMP Revision Notice Response R0 for additional information.

(e) CBR values exclude foundational costs

(f) Covered Conductor is estimated to be approximately 52% effective in mitigating EPSS outages but has no impact on PSPS planned outages. The resulting blended average effectiveness for Outage Program (defined as PSPS and EPSS) risk is 23%.

(g) Undergrounding eliminates the need to implement outage programs (i.e. PSPS and EPSS) for the undergrounded lines because they do not pose the same risk as overhead assets during the extreme weather conditions that drive outage program events. However, as explained in Section 8.2.1 and 8.2.2, the degree to which an area with underground lines may still be subject to outage events depends on whether, and how much, the upstream line sections have been overhead hardened or undergrounded.

(h) Distribution routine patrol includes work on the legacy TRI. Updated Expected % Risk Reduction as result of Critical Issue RN-PGE-26-09 updated workplan. See 2026-2028 WMP Revision Notice Response R0 for additional information.

PG&E provides below a step-by-step calculation showing how it derived the values provided in Table 6-3.

Activity Effectiveness – Overall Utility Risk

The effect of activities on overall risk is a measure of the percentage decrease in overall risk from the activity. PG&E evaluates that risk using the bow tie methodology (see Section 5.1.1 above). Overall Utility Risk is the sum of Wildfire Risk + PSPS risk + EPSS risk, aggregated from the Enterprise Risk Model (MAVF).

Our Overall Utility Risk is calculated as follows:

Overall Utility Risk = Wildfire Risk (Dx, Tx, Sub) + PSPS Risk + EPSS Risk

Enterprise Risk (MAVF) = (17,074 Dx + 2,314 Tx + 36 Sub) + 1,953 + 1,049 = 22,426

The following is an example of the effectiveness calculation with EPSS:

Overall Risk without EPSS = Overall Risk – EPSS Risk = 22,426 - 1,049 = 21,377

Overall Risk with EPSS = Overall Risk without EPSS + EPSS Risk – Wildfire Risk Reduction from EPSS = 21,377 + 1,049 – 10,611 = 11,815

$$\text{Effectiveness} = \frac{\text{Overall Risk without EPSS } - \text{Overall Risk with EPSS}}{\text{Overall Risk without EPSS}} \times 100$$

$$\text{Effectiveness} = \frac{21{,}337 - 11{,}815}{21{,}337} \times 100 = 45\%$$

The following is an example of that calculation with PSPS.

Overall Risk without PSPS = Overall Risk – PSPS Risk = 22,426 - 1,953 = 20,473

Overall Risk with PSPS = Overall Risk without PSPS + PSPS Risk – Wildfire Risk Reduction from PSPS = 20,473 + 1,953 – 16,257 = 6,169

$$\text{Effectiveness} = \frac{\text{Overall Risk without PSPS } - \text{Overall Risk with PSPS}}{\text{Overall Risk without PSPS}} \times 100$$

$$\text{Effectiveness} = \frac{20{,}473 - 6{,}169}{20{,}473} \times 100 = 70\%$$

Activity Effectiveness – Wildfire Risk

To calculate the effect of covered conductor installation and undergrounding of electric lines and equipment at reducing wildfire risk, we first conduct a study where subject matter experts (SME) are asked to fill out a questionnaire about the effectiveness of these activities against roughly 2,000 failure modes. For each failure mode, the SME indicates a categorical level of effectiveness, which is then converted to a percentage representing the fraction of ignitions that can be prevented by this treatment. We then compute the effectiveness of each activity as the average of the failure mode effectiveness values, weighted by the proportion of outages that correspond to each failure mode. This formulation is described in the equation below.

$$\text{Effectiveness} = \frac{\sum_{i=1}^{K} E_i \cdot c_i}{\sum_{i=1}^{K} c_i}$$

Where K is the number of failure modes considered, E is the SME judgement of effectiveness for a given failure mode, i, and c is the count of outages that have resulted from failure mode i.

The effect of distribution tag work, pole clearing, service drop breakaway connectors, transmission shunt splices, and transmission conductor segment replacement are based on SME judgment of how much each activity will reduce risk at the location in which the activity is being performed.

The effect of EPSS at reducing wildfire risk is calculated with the following formula:

$$\text{Effectiveness} = \left(1 - \frac{p_1}{p_2}\right) \times 100\%$$

$$\text{Where } p_1 = \frac{\text{count of ignitions with EPSS}}{\text{circuit} - \text{mile days with EPSS}}$$

$$\text{and } p_2 = \frac{\text{count of ignitions without EPSS}}{\text{circuit} - \text{mile days without EPSS}}$$

Table PG&E-6.2.1.2-1 shows an example of this calculation using ignition and EPSS activation data from R3 and above fire potential index (FPI) conditions in HFRA/HFTD.

TABLE PG&E-6.2.1.2-1:
CONTINGENCY TABLE FOR EPSS EFFECTIVENESS CALCULATION

	Ignitions	Circuit-Mile Days	p	$\frac{p_1}{p_2}$	Effectiveness
EPSS	64	7,949,193	8.05×10^{-6}	0.348	65%
Non-EPSS	247	10,672,567	2.31×10^{-5}		

The effect of PSPS on reducing catastrophic and destructive fires is based on a lookback analysis applying 2021 PSPS guidance to 2012-2020 historical fires with detected size greater than 1,000 acres. This analysis shows that operating under 2021 PSPS guidance could have prevented 100 percent of historical catastrophic and destructive fires. Since the 2021 guidance is calibrated using historical fires, we have reduced the effectiveness to 95 percent based on SME judgment.

Activity Effectiveness – Outage Program Risk

To calculate the effect of EPSS and PSPS on outage program risk, we determine the percentage increase in the baseline outage risk from the inclusion of each mitigation. We then take the complement of that percentage.

The following is an example of this calculation as applied to EPSS.

$$\text{Effectiveness} = \left(1 - \frac{\text{Mitigation Outage Risk} + \text{Baseline Outage Risk}}{\text{Baseline Outage Risk}}\right) \times 100$$

$$\text{Effectiveness} = \left(1 - \frac{926 + 1{,}265}{1{,}265}\right) \times 100 = -73\%$$

The following is an example of this calculation as applied to PSPS:

$$\text{Effectiveness} = \left(1 - \frac{\text{Mitigation Outage Risk} + \text{Baseline Outage Risk}}{\text{Baseline Outage Risk}}\right) \times 100$$

$$\text{Effectiveness} = \left(1 - \frac{742 + 1{,}265}{1{,}265}\right) \times 100 = -59\%$$

Cost Benefit Scores

The cost benefit ratios (CBR) in Table 6-3 were generated using the Enterprise Risk Models

The CBR is calculated by dividing the dollar value of the mitigation benefit by the mitigation cost estimate. The value of the numerator and denominator are in present values. This formula can account for execution of work and costs over multiple years.

$$CBR = \frac{\textit{[NPV of Risk Reduction} \text{ (in risk-adjusted \$M)]}}{\textit{[NPV of Program Costs} \text{ (in \$M)]}}$$

The Overall CBR is a summation of all program benefits, including the CBR for Wildfire + Outage Program Risk.

$$Overall\ CBR\ (Column\ 6) = \frac{\textit{Wildfire NPV RR}}{\textit{NPV Program Costs}}(column\ 7) + \frac{\textit{Reliability NPV RR}}{\textit{NPV Program Costs}}(Column\ 8)$$

For each risk (i.e. wildfire and reliability) risk reduction is evaluated based on an understanding of baseline and post mitigation risk for each program in review. Post mitigation risk is determined by understanding of the effectiveness of the program.

$$Post\ Mitigation\ Risk = \textit{Baseline Risk X Program Effectiveness}$$

$$\text{Risk Reduction = Baseline Risk – Post Mitigation Risk}$$

The total Risk Reduction (RR) for each program is calculated for the entire benefit length of the activity (t), discounting of inflation (i).

$$NPV\ RR = \frac{RRo}{(1+i)^0} + \frac{RR1}{(1+i)^1} + \frac{RR2}{(1+i)^2} + \ldots. + \frac{RRt}{(1+i)^t}$$

NPV Costs are calculated similarly based on the year (y0) of the future investment value (FV), and discounting for inflation (i).

$$NPV\ Cost = \frac{FV}{(1+i)^{Y0-NPVyear}}\ X\ PVRR$$

Additionally, for capital projects, a Present Value of Revenue Requirement (PVRR) multiplier is applied to the NPV cost for a project. This is a financial measure that has traditionally been used by public utilities subject to cost-of-service regulation. PVRR represents the present value of revenue that must be collected from customers to pay for all the costs (net of benefits) incurred on a project, including a fair and reasonable rate of return on investment, over the life of the project.

Percentage of HFTD Covered

To calculate the expected percentage of HFTD covered for each activity, we divide the units being worked on by the activity in HFTD by the total units in HFTD. The following is an example calculation, using service drop breakaway connector installation as an example. The values are used to illustrate the mechanics of the calculation.

For breakaway connector installation, the expected installations in HFTD from January 1, 2026, through December 31, 2028 = 3,000 service points

Total number of service points in HFTD = 510,616 service points

The expected % HFTD covered for the breakaway connector installation activity from 2026 to 2028 is:

$$\%\text{HFTD Covered} = \frac{\text{units of activity in HFTD}}{\text{total units within HFTD}} \times 100$$

$$= \frac{3000}{510{,}616} \times 100 = 0.58\%$$

Percentage of HFTD/HFRA Covered

To calculate the expected percentage of HFRA/HFTD covered for each activity, we divide the units being worked on by the activity in HFTD and HFRA by the total units in HFTD and HFRA. The following is an example calculation, using covered conductor installation program data. The values are used to illustrate the mechanics of the calculation.

For covered conductor installations, the expected installations in HFTD/HFRA from January 1, 2026 through December 31, 2028 = 718 circuit miles

The total primary overhead miles within the HFTD and HFRA = 25,000 circuit miles

The expected % HFRA covered for the covered conductor installations activity from 2026 to 2028 is:

$$\%\text{HFTD/HFRA Covered} = \frac{\text{units of activity in HFTD/HFRA}}{\text{total units within HFTD/HFRA}} \times 100$$

$$= \frac{718}{25{,}000} \times 100 = 2.9\%$$

Expected Risk Reduction

To calculate percent Risk Reduction, we first calculate Overall Utility Risk which is the sum of Wildfire Risk + PSPS risk + EPSS risk, aggregated from the Enterprise Risk Model (MAVF). Our Overall Utility Risk is:

Overall Utility Risk = Wildfire Risk (Dx, Tx, Sub) + PSPS Risk + EPSS Risk

Enterprise Risk (MAVF) = (17,074 Dx + 2,314 Tx + 36 Sub) + 1,953 + 1,049 = 22,426

After determining Overall Utility Risk, we calculate risk reduction based on the difference between pre- and post-mitigation risk related to Operational Mitigations and System Resilience. Operational Mitigations are generally mitigations that reduce risk within the given year, but the risk the following year is expected to return as emerging risk arises or the benefits are not sustained unless through continuous operation.

For each mitigation initiative, risk reduction is calculated based on: (1) the amount of risk targeted within the scope of the program and (2) the amount of risk reduction the program addresses overall. For example, the complete replacement of all non-exempt equipment to exempt equipment provides 100 percent reduction of the non-exempt equipment risk, but for the overall wildfire risk it provides only a small subset of risk reduction, given that non-exempt equipment is only a small percentage of the overall wildfire risk. Below we describe the high-level calculation. These calculations are done individually at the circuit segment or structure levels, calculating both pre- and post-mitigation frequency and risk across the entire work portfolio. The values used in the example calculations below do not reflect specific commitments and/or do not necessarily align to targets in this WMP. The values are used simply to illustrate the mechanics of the calculation. The example calculations are shown in Table PG&E-6.2.1.2-2, below.

TABLE PG&E-6.2.1.2-2:
EXAMPLE CALCULATIONS FOR UNDERGROUNDING AND COVERED CONDUCTOR INSTALLATION

Step	Wildfire Risk Value	Comments
WILDFIRE RISK REDUCTION		
Total WDRM Risk	1,204	Total Risk Score (uncalibrated) to measure workplan
Workplan WDRM Risk Exposure	25	Risk Score associated with the miles workplan is addressing
Effectiveness	98%	Program Effectiveness applied against targeted risk exposure
Workplan Wildfire Risk Reduction	25 * 98% = 24.5	Risk Reduction based on program effectiveness
WDRM to Enterprise MAVF Calibration	17,704 / 1,204 = 14.70	Calibrating WDRM to Enterprise MAVF Distribution Wildfire Score
Workplan Risk Reduction	24.5 * 14.70 = 360	Calibrating Risk Reduction to Enterprise MAVF
PSPS RISK REDUCTION		
Total PSPS Risk	1,953	Total PSPS Risk Score
Total Distribution PSPS Risk	1,294	Total PSPS Risk Score attributed to Distribution scoping
Workplan PSPS Risk Exposure	19	Risk Score associated with the miles workplan is addressing
Effectiveness	100%	Program Effectiveness applied against targeted risk exposure
Risk Reduction	19 * 100% = 19	Risk Reduction based on program effectiveness
EPSS RISK REDUCTION		
Total EPSS Risk	1,049	Total EPSS Risk Score
Workplan EPSS Risk Exposure	7	Risk Score associated with the miles workplan is addressing
Effectiveness	100%	Program Effectiveness applied against targeted risk exposure
Risk Reduction	7 * 100% = 7	Risk Reduction based on program effectiveness
OVERALL RISK REDUCTION		
Total Overall Risk Reduction	360 + 19 + 7 = 386	Total Overall Risk Reduction
Total Overall Utility Risk Reduction %	386 / 22,426 = 1.7%	Total Overall Utility Risk Reduction %

Table PG&E-6.2.1.2-3 is an example of the steps taken to calculate the risk reduction related to equipment replacement and maintenance backlog programs.

TABLE PG&E-6.2.1.2-3:
EXAMPLE CALCULATIONS FOR BACKLOG TAGS

Step	Wildfire Risk Value	Comments
Total Overall Utility Risk	22,426	
Total Distribution Wildfire Risk	17,074	
Total Unit Count	66.8K	Number of open tags
Workplan Unit Count	16.7K	Number of expected units worked in 2026 workplan
Exposure	16.7K / 66.8K = 25%	Workplan/total count
Total Unit Risk Score	13,400	Total risk score of open tags
Workplan Unit Risk Score	3,350	Workplan risk score of open tags
Risk Exposure	25%	Percent tag risk being mitigated
WDRM Equipment Risk Exposure	35%	Percent of distribution risk associated with equipment
Weighted Effectiveness	90%	Discounted effectiveness value for equipment
Detectability	15%	Percent of ignitions that are detectable via inspection, creating a tag
Risk Reduction	13,400*25%*35%*90%*15% = 158	
Risk Reduction	158 / 22,426 = 0.7%	Risk Reduction/Total Utility Risk

Table PG&E-6.2.1.2-4 is an example of the steps taken to calculate the expected percent risk reduction of pole clearing, distribution routine patrols, and breakaway connector installation. The example uses data for pole clearing, but the steps are the same for the other programs listed.

TABLE PG&E-6.2.1.2-4:
EXAMPLE CALCULATIONS FOR POLE CLEARING, DISTRIBUTION ROUTINE PATROLS, AND BREAKAWAY CONNECTOR INSTALLATION

Step	Wildfire Risk Value	Comments
Total Overall Utility Risk	22,426	
Total Distribution Wildfire Risk	17,074	
Total WDRM Risk	1,204	Total Risk Score (uncalibrated) to measure workplan
Workplan WDRM Risk Exposure	7	Risk Score associated with the miles workplan is addressing
Effectiveness	20%	Program Effectiveness applied against targeted risk exposure
Workplan Wildfire Risk Reduction	7 * 20% = 1.5	Risk Reduction based on program effectiveness
WDRM to Enterprise MAVF Calibration	17,704 / 1,204 = 14.70	Calibrating WDRM to Enterprise MAVF Distribution Wildfire Score
Workplan Risk Reduction	1.5 * 14.70 = 22	Calibrating Risk Reduction to Enterprise MAVF
Total Overall Utility Risk Reduction %	22 / 22,426 = 0.1%	Total Overall Utility Risk Reduction %

Table PG&E-6.2.1.2-5 is an example of the steps taken to calculate the expected percent risk reduction of transmission shunt splice installation and transmission conductor segment replacement. The example uses data for transmission conductor segment replacement, but the steps are the same for the other programs listed.

TABLE PG&E-6.2.1.2-5:
EXAMPLE CALCULATIONS FOR POLE CLEARING, DISTRIBUTION ROUTINE PATROLS, AND BREAKAWAY CONNECTOR INSTALLATION

Step	Wildfire Risk Value	Comments
Total Overall Utility Risk	22,426	
Total Non-Vegetation Transmission Wildfire Risk	644	
Total WTRM Risk	42,162	Total Risk Score (uncalibrated) to measure workplan
Workplan WTRM Risk Exposure	1304	Risk Score associated with the miles workplan is addressing
Effectiveness	75%	Program Effectiveness applied against targeted risk exposure
Workplan Wildfire Risk Reduction	1304 * 75% = 978	Risk Reduction based on program effectiveness
WTRM to Enterprise MAVF Calibration	644 / 42,162= 0.015	Calibrating WTRM to Enterprise MAVF Transmission Wildfire Score
Workplan Risk Reduction	978 * 0.015 = 15	Calibrating Risk Reduction to Enterprise MAVF
Total Overall Utility Risk Reduction	15 / 22,426 = 0.07%	Total Overall Utility Risk Reduction %

6.2.1.3 Projected Risk Reduction on Highest-Risk Circuits Over the 3-Year WMP Cycle

The objective of the service territory risk reduction summary is to provide an integrated view of wildfire risk reduction across the electrical corporation's service territory. The electrical corporation must provide the following information:

- *Tabular summary of numeric risk reduction for each high-risk circuit within the Top 20 percent of overall utility risk, showing risk levels before and after the implementation of activities. This must include the same circuits, segments, or span IDs presented in Section 5.5.2. The table must include the following information for each circuit:*
  - *Circuit, Segment, or Span ID: Unique identifier for the circuit, segment, or span;*
- *If there are multiple activities per ID, each must be listed separately, using an extender to provide a unique identifier;*
  - *Overall Utility Risk: Numerical value for the overall utility risk before and after each activity;*
  - *Initiative Activities by Implementation Year: Initiative activities the electrical corporation plans to apply to the circuit in each year of the WMP cycle; and*

In response to Critical Issue RN-PGE-26-02, Table 6-4 (now referred to as Table 6-4A), Summary of Risk Reduction for Top Risk Circuit Segments has been revised (now referred to as Table 6-4B) to represent the risk per primary overhead mile.

Table 6-4B below shows our summary of risk reduction activities for the top-risk circuits where PG&E's workplans identify the work locations[54]. Table 6-4B is based on our workplans as of July 23, 2025. The activities listed below are not objectives or targets for quarterly or annual reporting purposes in connection with the 2026-2028 WMP. There are various factors that may impact project completion schedules and therefore impact risk reduction in certain years, for example, external constraints like permitting and customer authorizations. We are including both control and mitigation initiatives in this table to demonstrate the layers of system protection, whether or not they provide in-year or long-term system resiliency benefits for the years listed below. Circuit segments in Table 6-4B are ranked by initial overall utility risk per primary overhead mile.

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[54] HFRA/HFTD distribution backlog tags are not included because the 2026-2028 scope of work is known, but the specific work to be performed each year has not been determined.

Table 15 of the Annual WMP Template will not be updated to reflect the changes in Table 6-4B because Table 15 captures the Overall Risk Score, not Overall Utility Risk per Primary Overhead Mile.

Table 6-4B below is an excerpt; due to the length of the table, the complete table is in Appendix F.

Table 6-4B is a list of the circuit segments with the highest overall utility risk per primary overhead mile in PG&E's service territory; however, PG&E does not prioritize wildfire mitigations based on this table. Each mitigation program develops a risk-prioritized work plan custom to the program's risk drivers and execution of work. For example, PG&E prioritizes system hardening work based on wildfire risk per mile, with the exception of circuit segments with very short lengths which artificially inflate their risk per mile.

Table 6-4A below shows our summary of risk reduction activities for the top-risk circuits where PG&E's workplans identify the work locations.[55] Table 6-4A is based on our workplans as of March 25, 2025. The activities listed below are not objectives or targets for quarterly or annual reporting purposes in connection with this WMP. There are various factors that may impact the actual execution and completion of work and that cannot directly be accounted for in the below table. For example, external constraints like permitting and customer authorizations may impact project completion schedules and that will impact the risk reduction in certain years. We are including both control and mitigation initiatives in this table to demonstrate the layers of system protection, whether or not they provide in-year or long-term system resiliency benefits for the years listed below. Circuit segments in Table 6-4A are ranked by mean wildfire risk and sorted by total risk.

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55 HFRA/HFTD distribution backlog tags are not included because the 2026-2028 scope of work is known, but the specific work to be performed each year has not been determined.

TABLE 6-4A:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUITS BY OVERALL RISK

Line No.	Circuit Segment Name	Initial Overall Utility Risk	2026 Activities	2026 Overall Utility Risk	2027 Activities	2027 Overall Utility Risk	2028 Activities	2028 Overall Utility Risk
1	CLAYTON 2212681608	99.70	Overhead hardening Undergrounding Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	20.82	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	19.71	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	18.54
2	BALCH NO 1 1101105414	91.52	Overhead hardening Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	24.20	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	24.17	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	24.13
3	CLOVERDALE 1102672	80.90	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	29.00	Overhead hardening Undergrounding Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	0.31	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	0.31
4	PLACERVILLE 21067522	72.83	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	27.96	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	27.08	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	26.13
5	PLACERVILLE 210611132	67.32	Overhead hardening Undergrounding Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	13.13	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	12.88	Pole clearing EPSS Vegetation routine patrol Vegetation hazard patrol	12.63

Note: Adjusted in response of Critical Issues RN-PGE-26-02. See 2026-2028 WMP Revision Notice Response R0 for additional information.

TABLE 6-4B:
SUMMARY OF RISK REDUCTION FOR TOP RISK CIRCUITS BY RISK PER MILE FOR CRITICAL ISSUE RN PGE 26 02

Line No.	Circuit Segment Name	Initial Overall Utility Risk	2026 Activities	2026 Overall Utility Risk	2027 Activities	2027 Overall Utility Risk	2028 Activities	2028 Overall Utility Risk
1	DUNBAR 11034882	176.19	Vegetation routine patrol Vegetation hazard patrol	176.19	Vegetation routine patrol Vegetation hazard patrol	176.19	Vegetation routine patrol Vegetation hazard patrol	176.19
2	PUEBLO 1104968601	126.37	EPSS Vegetation routine patrol Vegetation hazard patrol	122.22	EPSS Vegetation routine patrol Vegetation hazard patrol	122.22	EPSS Vegetation routine patrol Vegetation hazard patrol	122.22
3	ARBUCKLE 110130376	97.21	Vegetation routine patrol Vegetation hazard patrol	97.21	Vegetation routine patrol Vegetation hazard patrol	97.21	Vegetation routine patrol Vegetation hazard patrol	97.21
4	VACAVILLE 111112342	82.76	EPSS Vegetation routine patrol Vegetation hazard patrol	81.88	EPSS Vegetation routine patrol Vegetation hazard patrol	81.88	EPSS Vegetation routine patrol Vegetation hazard patrol	81.88
5	BALCH NO 1 1101CB	72.56	EPSS Vegetation routine patrol Vegetation hazard patrol	25.24	EPSS Vegetation routine patrol Vegetation hazard patrol	25.24	EPSS Vegetation routine patrol Vegetation hazard patrol	25.24

Note: Adjusted in response of Critical Issues RN-PGE-26-02. See 2026-2028 WMP Revision Notice Response R0 for additional information.

6.2.2 Interim Activities

For each activity that will require more than one year to implement,[56] *the electrical corporation must evaluate the need for interim activities that will reduce risk until the primary or permanent activity is in place. In this section of its WMP, the electrical corporation must provide a description of the following:*

- *The electrical corporation's procedures for evaluating the need for interim risk reduction. If an electrical corporation determines that interim activities are not necessary for a given activity, it must explain why and how it is monitoring wildfire and PSPS risk while working to implement the activity;*
- *The electrical corporation's procedures for determining which interim activities to implement;*
- *The electrical corporation's characterization of each interim activity and evaluation of its specific capabilities to reduce risks, including:*
  - *Potential consequences of risk event(s) addressed by the improvement/activity;*
  - *Frequency of occurrence of the risk event(s) addressed by the improvement/activity; and*
- *The electrical corporation's procedures for evaluating and implementing any changes in initiative effectiveness and prioritization based on time for implementation and use of interim activities, including:*
  - *The cumulative risk exposure of its activity portfolio, accounting for the time value of risk as part of activity comparisons.*

Each interim activity planned by the electrical corporation for implementation on high-risk circuits must be listed as an activity in Sections 8-12. In addition, the electrical corporation must discuss interim activities in the relevant mitigation initiative (initiative) sections of the WMP and include the activities in the related target tables.

As noted above, PG&E's risk mitigation framework is divided into four categories: (1) Comprehensive Monitoring and Data Collection, (2) Operational Mitigations, (3) System Resilience, and (4) Community Support. We rely on our operational mitigations as interim mitigations to reduce system risk until more permanent, long-term System Resilience mitigations can be fully deployed.

We evaluate the need for interim risk reduction based on the time and resources required to implement more permanent solutions. If there is any chance that a portion of the system will be exposed to risk that cannot be managed through our operational

56 *See Section 6.1.3.3. A length of one year was selected given the need to reduce wildfire risk in areas identified as high risk during active fire seasons that would otherwise be unaddressed while the primary activity is being implemented.*

mitigations pending the implementation of System Resilience mitigations, we will look to implement an interim solution. We determine which interim mitigation(s) to implement following the procedures described in Section 6.1.3 above.

We rely on operational mitigations in these same areas to reduce risk pending the implementation of these more permanent mitigations. The operational mitigations that provide interim risk reduction pending the installation of system hardening are described more fully in the sections listed below. The approximate risk reduction value for these activities, where available, is listed in Table 6-3.

The operational mitigations we deploy include: (1) PSPS where we de-energize a power line due to extreme weather conditions as a last resort to avoid an ignition; (Section 7); (2) EPSS, which reduces the time it takes for line protective devices to de-energize a powerline when a fault occurs (Section 8.7.1.1); (3) DCD technology which improves the ability to detect and isolate high impedance faults before an ignition can occur (Section 8.7.1.1); (4) Community Microgrid Enablement Program and Microgrid Incentive program to support energy resilience (Section 8.2.7.3); and (5) Temporary Distribution Microgrids, which support community resilience during PSPS events (Section 8.2.7.2). PSPS, EPSS, and DCD may continue to be used as both interim mitigations and long-term mitigations should conditions warrant their use.

SIPTs provide additional support to avoid potential ignitions and reduce the fire spread if an ignition occurs. (Section 8.7.2).

Shorter-term mitigations are used to address risks by strengthening and extending the life of the components. Below are examples of these shorter-term mitigations:

- Shunt splice installation on top of an existing splice that has been identified as having a higher risk of failure. This installation eliminates the splice as a single point of failure. (Section 8.2.5.1)

- Conductor segment replacements target the segments in a line with higher risk of failure due to asset type such as small-size conductors or localized threats such as vibration. These targeted segments can be replaced to reduce failure risk without rebuilding the entire line. This reduces risk for lines where the conductor segments are at higher risk but the structures are in good condition and there is no additional electrical capacity need to increase the conductor size. (Section 8.2.5.1)

- Wood pole reinforcement provides additional strength near the base of wood poles, which can reduce the risk of failure by restoring the strength at the groundline and extend the life of the assets. (Section 8.2.3)

In addition to the above interim mitigations, PG&E also installs an additional layer of protection by combining the above interim mitigation with additional mitigations as local conditions require pending the installation of covered conductor. Mitigations include real-time asset condition monitoring, pole clearing, utility defensible space, substation defensible space, asset inspections, and vegetation management. Where overhead system hardening is installed rather than underground conductor, PG&E will continue these activities to manage the risk profile in these areas.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 7

PUBLIC SAFETY POWER SHUTOFF

7. Public Safety Power Shutoff

In this section,[57] *the electrical corporation must provide an overview narrative of planned initiative actions to reduce the impacts of PSPS events.*[58] *Impacts include:*

- *Duration;*
- *Frequency; and*
- *Scope – Number of Customers.*

The narrative must summarize how the electrical corporation will reduce the need for, and impact of, future PSPS implementation on circuits that have been frequently deenergized, as listed in Table 4-3 in Section 4.3.

Furthermore, the narrative should describe any lessons learned for PSPS events occurring since the electrical corporation's last WMP submission and overall impacts to mitigation methodology in terms of reducing PSPS events in the future.

The PSPS Program temporarily turns off power in specific areas during extreme weather conditions to prevent the electric system from becoming a potential source of ignition. High winds can cause tree branches and debris to contact energized electric lines, which can potentially lead to a wildfire. PG&E initiates PSPS events as a last resort measure to keep our customers and communities safe. PG&E estimates PSPS is 95 percent effective at reducing catastrophic wildfire risk and, for this reason, considers PSPS to be a cornerstone of PG&E's operational mitigations. From 2019 through 2024, PG&E implemented 27 PSPS events that mitigated 1,439 instances of damage or hazards during high-risk weather conditions which had the potential to become catastrophic fires.

We know that losing power is disruptive for our customers; for this reason, we are working tirelessly to make our system safer and more resilient and reduce the impact of PSPS events for our customers and communities. We remain committed to executing our PSPS Program in a manner that complies with CPUC directives.[59]

PG&E experienced two PSPS events in 2023 and six PSPS events in 2024. Table PG&E-7-1 below is a summary of these and other events in the past seven years, including the duration, frequency, and scope of the events:

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[57] *Annual information included in the following section must align with the applicable data submission.*

[58] *Pub. Util. Code § 8386(c)(8).*

[59] CPUC directives include: Resolution ESRB-8, D.19-05-042, D.20-05-051, and D.21-06-034.

TABLE PG&E-7-1:
PSPS EVENT STATISTICS

Year	Number of Events Where De-Energization Was Initiated[a]	Total Circuits De-Energized[b]	Total Customers Impacted[c]	Total Customer Minutes of Interruption (CMI)[d]
2018	1	43	55,864	87,878,279
2019	8	1,842	2,036,019	5,513,240,050
2020	6	817	649,685	1,336,601,298
2021	5	237	80,391	147,807,660
2022[e]	–	–	–	–
2023	2	27	5,098	5,331,165
2024	6	242	50,519	97,112,035

(a) Number of Events Where De-energization Was Initiated: Number of instances where utility operating protocol requires de-energization of a circuit thereof to reduce ignition probability per year. This is only for events in which de-energization ultimately occurred.

(b) Circuits De-Energized: The cumulative sum of circuits de-energized by each PSPS event per year. If the same circuit was impacted by two different PSPS events, the circuit will be counted twice.

(c) Customers Impacted: The cumulative sum of customers impacted by each PSPS event per year. If multiple PSPS events impact the same customer, the customer is counted each time in the overall impact.

(d) CMI: The cumulative sum of customer minutes of de-energization due to PSPS events per each year (if multiple PSPS events impact the same customer, the customer minutes of de-energization is accounted for in each of the events for the given customer).

(e) We had no PSPS events in 2022.

Efforts to Reduce the Duration, Frequency, and Scope of PSPS Events

We are taking the following actions to reduce the impacts of duration, frequency, and scope of PSPS events:

1) Duration: The amount of time customers are out of power. PG&E is planning to continue to leverage Supervisory Control and Data Acquisition (SCADA) devices, which will reduce the time it takes to de-energize a circuit, see Section 8.2.11.2.

2) Frequency: The number of PSPS events is driven by weather, in particular wind speed and fuel conditions, both of which are difficult to reduce. However, PG&E is continuously improving our risk model sensitivity to weather, vegetation, and fuel conditions through the adoption of changes in our FPI, Ignition Probability Weather, and Operability Assessment models, see Section 10.6.

3) Scope: PG&E plans to reduce the scope of PSPS events by limiting the number of impacted customers as follows:

    a) Undergrounding: Undergrounding may mitigate PSPS activity in areas where lines are buried because the lines will no longer pose an ignition risk during the extreme weather conditions that drive PSPS events. However, undergrounding does not always eliminate PSPS risk for the directly-connected customers, especially when the undergrounded line remains connected to an overhead line (either upstream or downstream) in an area subject to PSPS events. For additional details on undergrounding, see Section 8.2.2.

b) Distribution Sectionalizing Devices: If a distribution asset needs to be de-energized during a PSPS event, a lack of switches or sectionalizing devices means that the entire circuit must be de-energized. Having sectionalizing ability, particularly on lines with tapped customers, provides the flexibility to only de-energize a portion of the line with the at-risk segment, rather than the entire line. This means that customers may remain in-service while still de-energizing the necessary portions of the line during PSPS events. For additional details on these devices, see Section 8.2.11.2.

c) Fixed Power Solutions: PG&E's Fixed Power Solutions (FPS) Program offers backup power support for our most vulnerable customers, critical facilities, and schools. This program provides financial incentives to qualified customers to reduce the cost of backup power installations, see Section 11.5.

See section above on "Efforts to Reduce the Duration, Frequency, and Scope of PSPS Events" on how PG&E will reduce the need for, and impact of, future PSPS implementation on circuits that have been frequently deenergized, as listed in Table 4-3 in Section 4.3. Additionally, see Section 4.3 for more information on frequently de-energized circuits.

Lessons Learned from PSPS Events Since the Last WMP

PG&E developed and began utilizing our FPI 5.0 model beginning in August 2024, which has several enhancements from the previous FPI 4.0 model as described in Section 10.6.1.[60] While we experienced six PSPS events in 2024, the scope of these events was reduced in comparison to 2019 and 2020 events. As shown in Table 4-3, the total number of impacted customers was reduced by 70 percent from 2020 while the number of circuits de-energized was reduced by over 90 percent over the same period.

The latest FPI 5.0 model allows us to scope outages at a much granular level, which is described in Section 10.6.1 under Existing Calculation Approach and Use.[61]

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60 In 2015, PG&E evaluated multiple public sources and methodologies for fire danger rating and benchmarked with SDG&E on their deployment of an FPI using high-resolution weather and fuel model data. In addition, PG&E scientists took instructor-led advanced courses in fire danger rating offered by the National Wildfire Coordinating Group to understand agency best practices and methodologies to evaluate fire danger. The early development work of FPI and Numerical Weather Prediction (POMMS project) is discussed in detail in PG&E's EPIC 1.05 project report.

61 The FPI 5.0 model was developed in 2022 and 2023 and approved for operations starting August 2024 and has several enhancements and improved skill over FPI 4.0. The key enhancements include finer spatial resolution of 0.7km^2 hexagons to capture greater detail of terrain and fuel categories compared to the previous 2x2km (4km^2) grid cell aggregation of fuels and terrain.

Additionally, PG&E collects lessons learned from staff following each PSPS event, and lessons are reported in Section 11.4 of the Post-Event Reports.[62] These lessons learned are incorporated into process improvements and addressed by specific Functional Areas.

During the July 2, 2024 PSPS event, we were able to reduce the event duration for some customers by temporarily re-energizing a line that serves a portion of the impacted customers due to dissipating winds in the morning before a second wave of adverse weather impacted the same customers later that day. This provided a window for customers who had been without power the night before to cool their homes and charge devices.[63] This was implemented with the expectation that a portion of these customers would be de-energized again for continued safety. We may offer temporary re-energization during future PSPS events where conditions allow.

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62 Post-Event Reports, available at: <https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program/public-safety-power-shutoffs.html#tabs-6e3912efa4-item-c4f1d89b80-tab>.

63 See *PG&E PSPS Report to the CPUC on July 2-3, 2024 De-Energization* (Jul. 18, 2024), available at: <https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/PGE_PSPS_Post-Event_Report_20240702-amended.pdf>.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 8

GRID DESIGN, OPERATIONS, AND MAINTENANCE

8. Grid Design, Operations, and Maintenance

Each electrical corporation's Wildfire Mitigation Plan (WMP) must include plans for grid design, operations, and maintenance programmatic areas.[64]

8.1 Targets

In this section, the electrical corporation must provide qualitative and quantitative targets for each year of the 3-year WMP cycle.[65] The electrical corporation must provide at least one qualitative or quantitative target for the following initiatives:

- *Grid Design and System Hardening (Section 8.2);*
- *Asset Inspections (Section 8.3);*
- *Equipment Maintenance and Repair (Section 8.4);*
- *Work Orders (Section 8.6);*
- *Grid Operations and Procedures (Section 8.7); and*
- *Workforce Planning (Section 8.8).*

Quantitative targets are required for Quality Assurance (QA) and Quality Control (QC). See Section 8.5, for detailed quantitative target requirements for QA and QC. Reporting of QA and QC quantitative targets is only required in Section 8.5.

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64 *Pub. Util. Code §§ 8386(c)(3), (10), (14).*

65 *All end-of-year (EOY) targets in all sections of the WMP must follow the calendar year.*

8.1.1 Qualitative Targets

The electrical corporation must provide qualitative targets for its 3-year plan for implementing and improving its grid design, operations, and maintenance,[66] *including the following:*

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable;*
- *A target completion date; and*
- *Reference(s) to the C section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated.*

This information must be provided in Table 8-1 below.

8.1.2 Quantitative Targets

The electrical corporation must list all quantitative targets it will use to track progress on its grid design, operations, and maintenance in its 3-year plan, broken out by each year of the WMP cycle. Electrical corporations will show progress toward completing quantitative targets in subsequent reports, including data submissions and WMP Updates.[67] *For each target, the electrical corporation must provide the following:*

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable;*
- *Projected targets and totals for each of the three years of the WMP cycle and relevant units for the targets;*
- *The percentage of each activity planned to be performed within High Fire Threat District (HFTD) and High Fire Risk Area (HFRA) (if applicable); and*
- *The expected percent risk reduction for each of the three years of the WMP cycle.*[68]

The electrical corporation's quantitative targets must provide enough detail to effectively inform efforts to improve the performance of the electrical corporation's grid design, operations, and maintenance initiatives. Each activity must have distinct, trackable targets associated with the activity, even if the electrical corporation tracks targets

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66 *Annual information included in this section must align with the applicable data submission.*

67 *Annual information included in this section must align with the applicable data submission.*

68 *The expected percent risk reduction is the expected percentage risk reduction per year, as described in Section 6.2.1.2.*

internally with activities combined. Only inspection-related activities are required to have quarterly targets, with all other activities only requiring EOY total targets. At its discretion, the electrical corporation may provide further granularity as available.

Table 8-1 includes the qualitative and the quantitative targets PG&E will use to track progress on Grid Design, Operations and Maintenance in the 2026-2028 period in the table format required by Energy Safety.

- Reporting: PG&E will use the targets in Table 8-1 below for quarterly compliance reporting including the Quarterly Data Report (QDR), Quarterly Notification (QN), and the Annual Report on Compliance (ARC). We note that, throughout this 2026-2028 WMP, we discuss current plans for wildfire-related activities beyond the targets in Table 8-1. The timing and scope of these additional activities may change. We will not be reporting on these additional activities in our QDR, QN, or ARC because they are not defined targets but are described in our 2026-2028 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All targets throughout this WMP are subject to External Factors. External Factors in this context are reasonable circumstances that may impact execution against targets including, but not limited to, physical conditions, environmental delays, landowner or customer refusals or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, wildfires, exceptions or exemptions to regulatory/statutory requirements, and other safety considerations.

- Utility Initiative Tracking IDs (Tracking IDs): We are including Tracking IDs in each section that has associated targets. Table 8-1 displays the Tracking IDs we are implementing to tie the targets to the narratives in the WMP. The Tracking IDs will also be used for reporting in the QDR.

- Percent Risk Impact: The "% Risk Impact" is calculated based on the risk reduction of the mitigation initiative divided by total overall utility risk. The "% Risk Impact" provided is an estimate based on the best available workplans applied against the latest risk models as of the time of this filing. In many cases, the workplans contain units exceeding the target presented to ensure target completion is feasible. We anticipate that as mitigation work takes place and as risk models and workplans are updated, the estimated "% Risk Impact" projections may change. Additionally, because inspections do not reduce risk in isolation, for inspection and line sensor related targets we include an "eyes-on-risk" value to provide insights into the level of risk being assessed.

- *HFTD, HFRA, Buffer Zone Areas: Unless stated otherwise, all initiatives described in Table 8-1 either involve work or audits on units or equipment located in, traversing, or energizing HFTD, HFRA, or Buffer Zone areas.*

TABLE 8-1:
GRID DESIGN, OPERATION, AND MAINTENANCE TARGETS BY YEAR

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID #)	Previous Tracking ID (if applicable)	Target Unit	2026 Target/ Status	% Planned in HFTD for 2026	% Planned in HFRA for 2026	% Risk Reduction for 2026	2027 Target/ Status	% Planned in HFTD for 2027	% Planned in HFRA in 2027	% Risk Reduction for 2027	2028 Target / Status	% Planned in HFTD for 2028	% HFRA planned in 2028	% Risk Reduction for 2028	3-Year Total	Section; Page Number
Grid Design, Operations, and Maintenance	Quantitative (Quarterly)	Detailed Inspection – Transmission (AI-04)	AI-04	Transmission Structures	22,000	96.5%	100%	63.78% (Eyes on Risk)	22,000	96.5%	100%	63.78% (Eyes on Risk)	22,000	96.5%	100%	63.78% (Eyes on Risk)	66,000	8.3.1; p. 232
Grid Design, Operations, and Maintenance	Quantitative (Quarterly)	Infrared Inspections – Transmission (AI-06)	AI-06	Circuit miles	2,500	94.6%	100%	72.95% (Eyes on Risk)	2,500	94.6%	100%	72.95% (Eyes on Risk)	2,500	94.6%	100%	72.95% (Eyes on Risk)	7,500	8.3.3; p. 235
Grid Design, Operations, and Maintenance	Quantitative (Quarterly)	Aerial Scan Inspections – Distribution (AI-07A)[a]	n/a	Distribution Poles	50,000	98%	100%	24% (Eyes on Risk)	20,000	99%	100%	12% (Eyes on Risk)	20,000	98%	100%	9% (Eyes on Risk)	90,000	8.3.8 p. 240
Grid Design, Operations, and Maintenance	Quantitative (Quarterly)	Detailed Inspections – Distribution (AI-07D) [a]	AI-07	Distribution Poles	300,000	98%	100%	33% (Eyes on Risk)	305,000	94%	100%	47% (Eyes on Risk)	215,000	98%	100%	48% (Eyes on Risk)	820,000	8.3.8 p. 240
Grid Design, Operations, and Maintenance	Quantitative	System Hardening – Undergrounding (GH-04)[b][e]	GH-04	Circuit Miles	360[c]	100%	100%	1.4%	307	100%	100%	2.2%	400	100%	100%	2.4%	1,067	8.2.2; p. 201
Grid Design, Operations, and Maintenance	Quantitative	System Hardening - Transmission Shunt Splices (GH-06)	GH-06	Shunt Splices	250	100%	100%	0.07%	250	100%	100%	0.07%	250	100%	100%	0.07%	750	8.2.5.1; p. 208
Grid Design, Operations, and Maintenance	Quantitative	System Hardening – Transmission Conductor Segment Replacement (GH-11)	GH-11	Conductor Segment	4	100%	100%	0.05%	5	100%	100%	0.05%	6	100%	100%	0.05%	15	8.2.5.1; p. 208
Grid Design, Operations, and Maintenance	Quantitative	Overhead Hardening – Distribution (GH-12)[e]	GH-01(d)	Circuit Miles	294	100%	100%	1.2%	190	98.7%	100%	1.0%	190	99.90%	100%	.06%	674	8.2.1; p. 184
Grid Design, Operations, and Maintenance	Quantitative	Line Removal Enabled by Remote Grid – Distribution (GH-14)[e]	GH-01	Circuit Miles	4	n/a100%	100%	.04%	0	n/a	n/a	n/a	0	n/a	n/a	n/a	4	8.2.7.1 p. 211
Grid Design, Operations, and Maintenance	Qualitative	Proactive Animal Abatement Feasibility Study – Transmission (GH-13)	n/a	n/a	Started; March 2026	n/a	n/a	n/a	In Progress; 2027	n/a	n/a	n/a	Completed; December 31, 2028	n/a	n/a	n/a	n/a	8.2.13.1; p. 226

TABLE 8 1:
GRID DESIGN, OPERATION, AND MAINTENANCE TARGETS BY YEAR
(CONTINUED)

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID #)	Previous Tracking ID (if applicable)	Target Unit	2026 Target/ Status	% Planned in HFTD for 2026	% Planned in HFRA for 2026	% Risk Reduction for 2026	2027 Target/ Status	% Planned in HFTD for 2027	% Planned in HFRA in 2027	% Risk Reduction for 2027	2028 Target / Status	% Planned in HFTD for 2028	% HFRA Planned in 2028	% Risk Reduction for 2028	3-Year Total	Section; Page Number
Grid Design, Operations, and Maintenance	Quantitative	Open Tag Reduction – Distribution Backlog (GM-03)	GM-03	Distribution EC Tags	Close 134% of the count of EC notifications created in HFTD/HFRA in 2025	100%	99%	0.6%	Close 153% of the count of EC notifications created in HFTD/HFRA from 2025 to 2026	100%	99%	0.6%	Close 160% of the count of EC notifications created in HFTD/HFRA from 2025 to 2027	100%	99%	0.6%	n/a	8.6.2; p. 321
Grid Design, Operations, and Maintenance	Qualitative	Updates on EPSS Reliability Study (GM-07)	GM-07	n/a	Completed; February 15, 2026	n/a	n/a	n/a	Completed; February 15, 2027	n/a	n/a	n/a	Completed; February 15, 2028	n/a	n/a	n/a	n/a	8.7.1.1; p. 332
Grid Design, Operations, and Maintenance	Quantitative	Service Breakaway Connectors (GM-14)	n/a	Service Breakaway Connectors	200	100%	100%	0.001%	1,400	100%	100%	0.007%	1,400	100%	100%	0.007%	3,000	8.2.10.6; p. 223
Grid Design, Operations, and Maintenance	Qualitative	Workforce Planning (GM-15)	n/a	n/a	Completed; May 1, 2026	n/a	n/a	n/a	Completed; May 1, 2027	n/a	n/a	n/a	Completed; May 1, 2028	n/a	n/a	n/a	n/a	8.8.1; p. 350

(a) In response to Critical Issue RN-PGE-26-06, the percent of risk reduction for detailed inspections and aerial inspections together account for 57 percent Eyes-on-Risk (EOR). PG&E aims to achieve a cumulative 57 percent EOR across aerial scan and detailed inspections. This EOR can be allocated in any way across the two inspections. See 2026-2028 WMP Revision Notice Response R0 for additional information.

(b) PG&E may include in these calculations the mileage and risk reduction from new system hardening technologies, such as Ground-Level Distribution Systems (GLDS) discussed in ACI PG&E-25U-03, Section 2.3.

(c) In the 2023-2025 WMP, PG&E provided a forecast of 440 undergrounding miles for 2026 (PG&E's 2023-2025 Base WMP R6, p. 408, Table 8.1.2-2). The 2026 miles were provided as a forecast only to align to the total miles approved in PG&E's 2023 GRC and were not a WMP target. Based on the undergrounding work completed in 2023 and 2024, and forecast for 2025, we are reducing the number of undergrounding miles needed to achieve the 18 percent risk reduction target for 2023-2026 that is a requirement of PG&E's 2023 GRC decision (Decision (D.) 23-11-069, Ordering Paragraph 22)

(d) In the 2023-2025 WMP, the covered conductor initiative (GH-01) included work associated with the system hardening program, including overhead covered conductor, system hardening undergrounding, and removal of overhead lines in HFTD, HFRA, or buffer zone areas. The covered conductor activity and target GH-12 have been updated for this revised 2026-2028 Base WMP to remove undergrounding work, which is captured in GH-04, and to remove line removal which is captured in GH-14 for line removal enabled by remote grid. See Critical Issue RN-PGE-26-05 in 2026-2028 WMP Revision Notice Response R0 for additional information.

(e) In response to Critical Issue RN-PGE-26-05, these targets and risk reduction estimates exclude system hardening for community rebuild purposes. See 2026-2028 WMP Revision Notice Response R0 for additional information.

8.2 Grid Design and System Hardening

In this section the electrical corporation must discuss how it is designing its system to reduce overall utility risk and what it is doing to strengthen its distribution, transmission, and substation infrastructure to reduce the risk of utility-related ignitions resulting in catastrophic wildfires.[69]

The electrical corporation is required to discuss grid design and system hardening for each of the following individual activities:

1) Covered conductor (CC) installation;

2) Undergrounding of electric lines and/or equipment;

3) Distribution pole replacements and reinforcements;

4) Transmission pole/tower replacements and reinforcements;

5) Traditional OH hardening;

6) Emerging grid hardening technology installations and pilots;

7) Microgrids;

8) Installation of system automation equipment;

9) Line removal (in the HFTD);

10) Other grid topology improvements to minimize risk of ignitions;

11) Other grid topology improvements to mitigate or reduce Public Safety Power Shutoff (PSPS) events;

12) Other technologies and systems not listed above; and

13) Status updates on additional technologies being piloted.

In Sections 8.2.1 – 8.2.13, the electrical corporation must provide a narrative that supports the qualitative targets identified in Section 8.1.1 including the following information for each grid design and system hardening activity:

- *Tracking ID;*
- *Overview of the Activity: A brief description of the activity including reference to related objectives and targets. Additionally, the overview must identify whether the activity is a program, project, pilot, or study;*
- *Impact of the Activity on Wildfire Risk:*

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69 Pub. Util. Code §§ 8386(c)(3), (6), (14)-(15).

  - *The expected percent wildfire risk reduction/effectiveness, with level of granularity included, (e.g., service territory, HFTD, circuit segment, etc.) for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100 percent means no risk remains after the electrical corporation completes the activity;*

  - *A trend analysis showing how implementation of the activity has reduced risk over time for each relevant risk and/or risk driver (e.g., vegetation contact for CC installation);*

  - *A discussion of how the activity impacts the likelihood and consequence of ignitions;*

- *Impact of the Activity on Outage Program Risk:*

  - *The expected percent reliability risk reduction/effectiveness for the activity, including an explanation of the calculation, a list of assumptions, and justifications for each assumption. A risk reduction/effectiveness of 100 percent means no risk remains after the electrical corporation completes the activity;*

  - *A discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk;*

  - *A discussion of how the activity impacts the likelihood and consequence of outage program events, including whether an area would still be subject to PSPS events after the electrical corporation completes the activity;*

  - *A discussion of how the activity impacts overall reliability, including how trends are being observed. This must include evaluation of number of outages occurring, the duration for those outages, and the number of customers affected during those outages;*

- *Updates to the Activity:*

  - *A list of the changes the electrical corporation made to the activity since its last WMP submission;*

  - *Justification for each of the changes, including references to lessons learned;*

  - *A list of planned future improvements and/or updates to the activity, including a timeline for implementation;*

  - *As applicable, a discussion of the status of any undergrounding work plans and progress, as required by Pub. Util. Code Section 8388.5(f)(2);*

- *As applicable, a discussion of any evaluations related to scoping grid hardening projects to account for future grid needs (e.g., load capacity, peak demand, system flexibility);*[70] *and*

- *Compatible activities:*
  - *A list of all activities that can be feasibly deployed in combination and which of these activities the electrical corporation is deploying in combination with the activity to increase risk reduction effectiveness, including the section number and a link to the corresponding WMP section. This must be consistent with the evaluations performed in Section 6.1.3.1.*

If the electrical corporation does not undertake one or more of the 13 activities listed above, the electrical corporation must provide a brief narrative for each activity, explaining why it does not undertake that activity.

PG&E's Grid Design and System Hardening initiative focuses on mitigating wildfire risk in Tier 2 and 3 HFTD and HFRA areas within PG&E's service territory. This initiative focuses on mitigating potential catastrophic wildfire risk and improving outage reliability related to transmission and distribution overhead assets.

PG&E's Grid Design and System Hardening initiative is risk informed. We discuss our risk analysis framework in Section 5 and our wildfire mitigation strategy in Section 6 of this WMP. In this section, we discuss our Grid Design and System Hardening activities.

PG&E's Grid Design and System Hardening initiative includes three of our most impactful mitigation activities: Covered Conductor (CC) Installation, remote grid installation, and Undergrounding. GH-12 is distribution overhead hardening via CC and is described in Sections 8.2.1 and 8.2.9.2 and 8.2.7.1. GH-14 is line removal enabled by remote grid and is described in Section 8.2.7.1. GH-04 is hardening via undergrounding and is discussed in Sections 8.2.1 and 8.2.2. Each of these mitigation activities is a tool that is applied depending on the risks and risk reduction needs in a specific location. In determining whether to overhead harden, construct a remote grid, or underground a location, PG&E considers each tool and its potential to reduce ignition and reliability risk. Because of this singular approach to determining whether to apply overhead hardening, remote grid, or undergrounding, there is overlap in how we respond to several of the prompts in Section 8.2.1 (Covered Conductor Installation), Section 8.2.7.1 (Remote Grids), and Section 8.2.2 (Undergrounding). To avoid repeating the same discussion in different sections, where there is overlap, we respond to the prompt in Section 8.2.1, and refer back to that discussion for the relevant prompt in the other sections.

PG&E's transmission system hardening activities include transmission pole/tower replacements and reinforcements, traditional overhead hardening of transmission

70 *These considerations must be in alignment with the CPUC's Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps, D.24-10-030.*

conductor, and transmission line removal. These activities are detailed in Sections 8.2.4, 8.2.5.1, and 8.2.9.1, respectively. Discussion on other grid design and system hardening grid topology improvements, technology, and pilots can be found in Sections 8.2.6 through 8.2.8, and Sections 8.2.10 through 8.2.13.

Effectiveness Analyses

PG&E's risk reduction/effectiveness calculations for programs in this section are provided in Table 6-3.

The trend analyses for wildfire risk and outage program risk (PSPS, EPSS), are provided for covered conductor and undergrounding in Table PG&E-8.2.1-5. PG&E is developing methods for performing this analysis at the risk driver-level for covered conductor.

8.2.1 Covered Conductor Installation

Tracking ID: GH-12

Overview of the Activity

PG&E's System Hardening initiative is focused on mitigating potential catastrophic wildfire risk and outage reliability risk caused by distribution overhead assets. The initiative includes overhead hardening via covered conductor (CC) installation.

PG&E's overhead hardening via CC target (GH-12) is shown in Table 8-1 and the Risk Impact of Activities are shown in Table 6-3 of Section 6.2.1.2.

Program Description

CC is the main mitigation implemented in our overhead hardening activity. CC installation involves replacing bare overhead primary conductor (voltage 22 kilovolt (kV) and below) and associated framing with conductor that is insulated with abrasion-resistant polyethylene coating (generally referred to as "covered conductor" and occasionally as "tree wire"). Installing CC can help reduce the likelihood of faults (a disruption in the normal flow of electricity) and, by extension, outages and ignitions due to line-to-line contacts, tree-branch contacts, and animal contacts. Installing CC on secondary lines has similar benefits to installing it on primary lines.

Overhead hardening is effective in several environments including:

a) Areas with lower PSPS risk that also have minimal tree fall-in risk with more short, grassy fuels;

b) Areas with limited ingress/egress risk; and

c) Terrain where undergrounding is not feasible or is cost-prohibitive due to the presence of steep slopes, hard rock, water crossings, and/or other considerations.

CC can also be effective against third-party impacts that can cause line slap, such as vehicles running into guy wires or poles.

Overhead hardening can be an effective mitigation for many transient type outages (i.e., brief power interruptions typically caused by temporary faults on power lines), as well as those caused by contact from vegetation (i.e., eucalyptus bark, palm fronds, branches, etc.), birds, other animals, and mylar balloons. Overhead hardening may also include hardening of other equipment on the pole, including, but not limited to, installing covered jumpers and animal protection when installing covered conductor. This comprehensive approach eliminates most exposed energized components and is effective in mitigating many phase-to-ground type outages. As such, overhead hardening may also be considered for buffer zones that are adjacent to HFTD or HFRA boundaries, or in non-HFTD or non-HFRA areas that experience recurring outages that may indicate wildfire risk (e.g., experiencing multiple contacts from vegetation).

Project Selection

PG&E has a comprehensive approach to determine the most appropriate hardening solution—whether overhead, line removal, or underground—for any specific location. This comprehensive approach to determining whether to apply overhead hardening, remote grid, or undergrounding is described here. It is equally applicable to our undergrounding activity described in Section 8.2.2.

PG&E's first step in its selection process is to identify high risk circuit segments. The methodology is described in more detail in Section 6.1.3. Once a high-risk overhead circuit segment is identified for system hardening, PG&E's engineering and field teams develop and analyze possible hardening solutions for that circuit segment (i.e., overhead hardening, undergrounding, removal or relocation). This includes conducting an economic analysis to select the primary mitigation type for that circuit segment. While PG&E will choose either overhead hardening, remote grid, or undergrounding as the primary mitigation, PG&E often implements a hybrid mitigation solution that consists of both overhead hardening and undergrounding on portions of the same circuit segment.

For circuit segments that are selected for overhead hardening as the primary mitigation, PG&E will analyze the proposed CC route to determine if there are areas with tree strike risk or locations that could be subject to ingress/egress issues. Undergrounding is the most effective system hardening method to mitigate tree strike risk and to address ingress and egress. Thus, if tree strike or ingress/egress issues are identified on a circuit segment selected for overhead hardening, PG&E may adopt a hybrid mitigation approach, in which case it would underground portions of that circuit segment to eliminate the tree strike and/or ingress/egress risk.

Similar to the hybrid approach that may be adopted on a circuit segment selected for overhead hardening, PG&E may install overhead hardening on portions of circuit segments selected for undergrounding. For example, during underground project scoping, PG&E may identify locations where it could be difficult or impossible to relocate lines underground. Specifically, in locations with hard rock, steep slopes, or at water crossings, PG&E may choose to overhead harden sections of line instead of undergrounding them to address these feasibility concerns. Although overhead hardening is less effective than undergrounding at reducing wildfire ignition risk, overhead hardening lines in these locations is usually less expensive than relocating lines to underground and still offers protection against ignition risk.

PG&E's System Hardening Project Scoping Decision Tree and Process is shown in Figure PG&E-8.2.1-1, Figure PG&E-8.2.1-2, and Figure PG&E-8.2.1-3 below. PG&E will use this decision tree and process to select projects that will begin in 2027.

See Revision Notice Response to Critical Issue RN-PGE-26-03 for more information on PG&E's decision-making process for system hardening projects.

FIGURE PG&E-8.2.1-1:
PG&E'S SYSTEM HARDENING PROJECT SCOPING DECISION TREE AND PROCESS (1 OF 3)

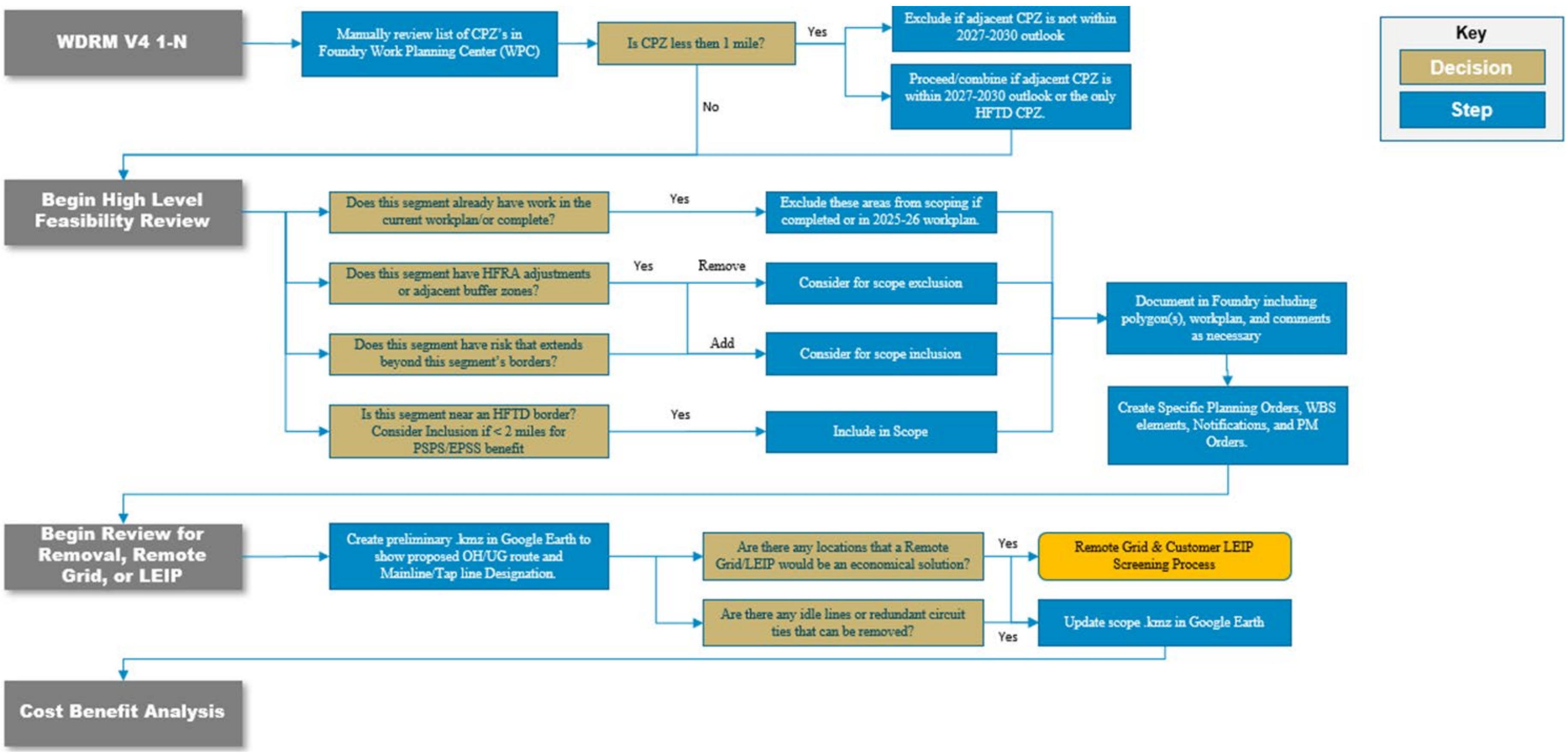


FIGURE PG&E-8.2.1-2:
PG&E'S SYSTEM HARDENING PROJECT SCOPING DECISION TREE AND PROCESS (2 OF 3)

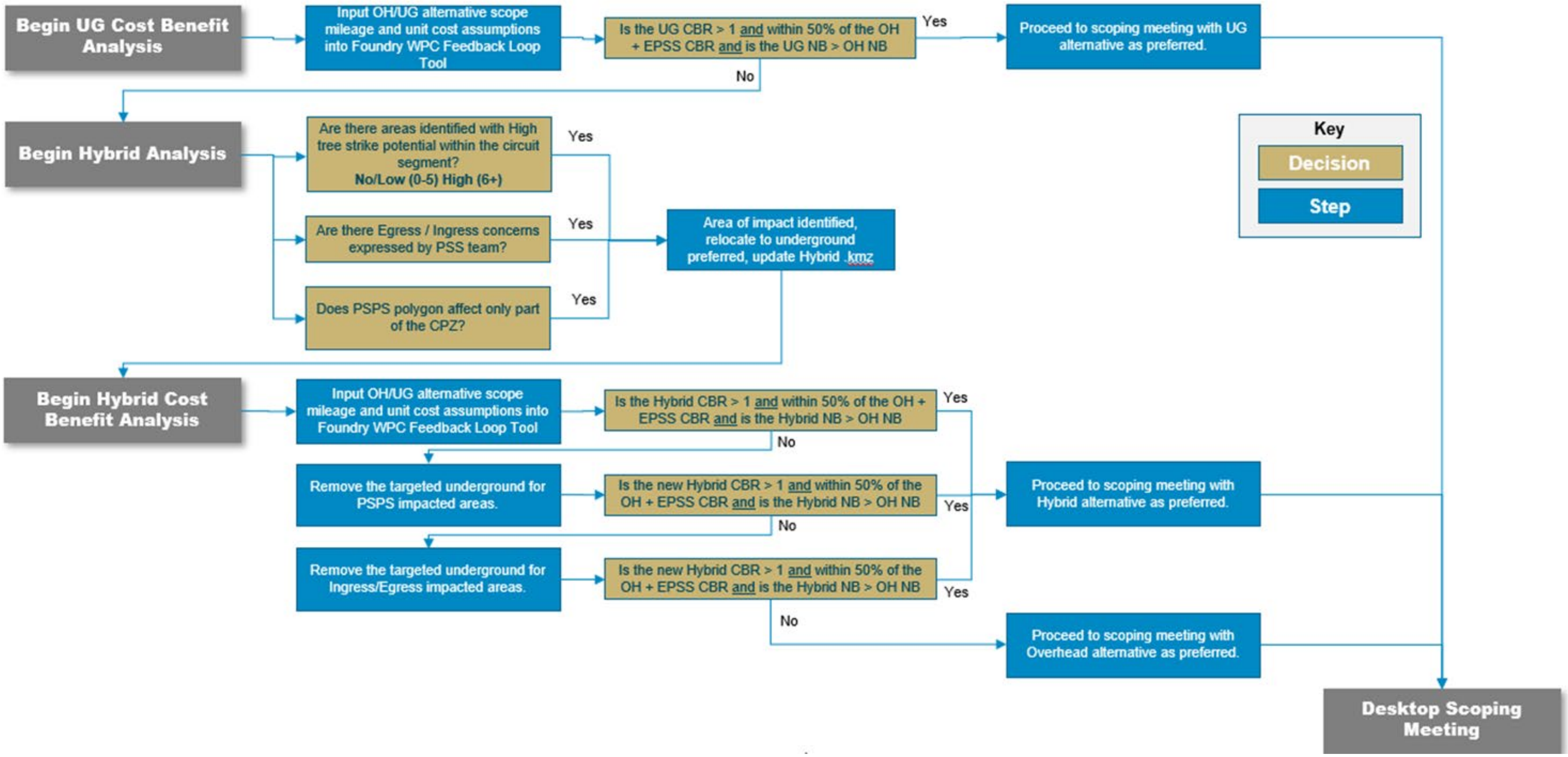
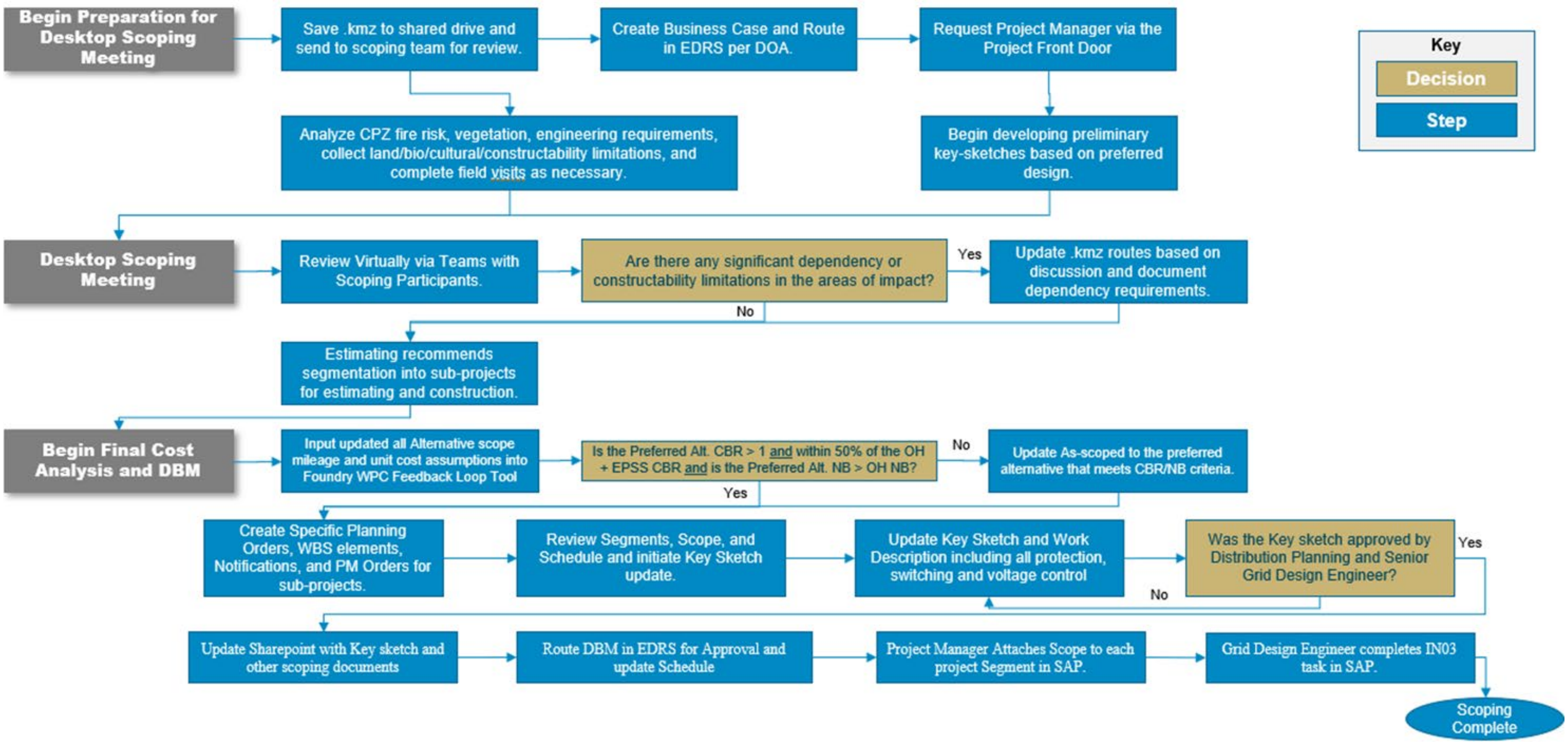


FIGURE PG&E-8.2.1-3:
PG&E'S SYSTEM HARDENING PROJECT SCOPING DECISION TREE AND PROCESS (3 OF 3)



PG&E intends to file an EUP after all EUP Guidelines are adopted by Energy Safety and the CPUC and anticipates transitioning the undergrounding program to the EUP for 2028. PG&E may need to adapt the project selection approach described above to align with the final EUP guidelines and approval conditions after the EUP is approved and goes into effect.

System Hardening in Fire Rebuild Areas

PG&E is responsible for expeditiously restoring electric services interrupted by wildfires. PG&E often refers to areas that have been impacted directly by wildfires within an HFTD as “Fire Rebuild” work. Work in areas impacted by wildfires outside of an HFTD area is referred to as “Community Rebuild” work.[71]

Immediately after a wildfire event, PG&E conducts a damage assessment and determines if damaged assets require hardening. Damaged assets that require hardening (i.e., overhead or underground) are considered for either the Fire Rebuild program (assets in HFTD areas) or for the Community Rebuild program (assets outside of HFTD areas). Damaged assets that do not require hardening and can be replaced “like-for-like” are tracked outside of the Fire Rebuild and Community Rebuild programs.

Fire-damaged assets are prioritized for expeditious rebuild and/or replacement. For Fire Rebuild and Community Rebuild work, PG&E assesses each damaged asset and determines the appropriate mitigation solution including overhead hardening, undergrounding, line removal, remote grid and customer buyout.[72] System hardening is deployed where significant rebuild is required (e.g., four or more spans and/or segments with intermittent damage) and other repairs will not suffice. PG&E determines whether to locate the new distribution line underground or replace the damaged assets with new infrastructure that is overhead hardened. All rebuild projects are executed to PG&E’s hardened standard. If PG&E determines that a damaged asset is an idle facility or a redundant tie (a tie that is no longer required to facilitate normal switching between circuits) then line removal may be an appropriate mitigation solution. Where damaged assets serve isolated or small groups of customers in the HFTD and temporary generation is available to serve customers in the near term, customer buyout or a remote grid may be the appropriate long-term mitigation.

Impact of the Activity on Wildfire Risk

Below we describe our process for calculating the effectiveness of our system hardening program activities—covered conductor, line removal enabled by remote grid , and undergrounding—and explain the relevant assumptions. The effectiveness values are presented in Table PG&E-8.2.1-3. CC has an average wildfire risk reduction effectiveness of 67 percent, or 79 percent with EPSS and Downed Conductor Detection

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71 Per response to Critical Issue RN-PGE-26-05, community rebuild are excluded from the targets in Table 8-1.

72 The customer buyout program is referred to as the LEIP “Line Elimination Incentive Plan.” PG&E enters an agreement with the customer that includes removal of the lines serving the customer through wildfire risk areas and compensation to the customer. The customer becomes responsible to provide their own remote energy needs.

(DCD). Undergrounding primary powerlines has an average wildfire risk reduction effectiveness of 98 percent, while undergrounding all powerlines (primary, secondary and service lines) has an effectiveness of 99 percent. The effectiveness of undergrounding is discussed in more detail in Section 8.2.2.

Calculating Wildfire Mitigation Effectiveness

PG&E uses its Wildfire Benefit Cost Analysis (WBCA) tool to calculate wildfire mitigation effectiveness at the circuit segment level. PG&E incorporates effectiveness values for each mitigation and combinations of mitigations into the WBCA by evaluating how successful each of them would be in mitigating a potential ignition risk resulting from particular combinations of unplanned outage events and equipment attributes ("outage combinations"). PG&E assessed the effectiveness of each of the mitigation alternatives against more than 2,700 outage combinations that have occurred in PG&E's HFTD areas during wildfire season. PG&E Subject Matter Experts (SME) reviewed each of the outage combinations, which consist of a basic event plus three additional attributes (supplemental cause of an ignition, failed/involved equipment, and equipment condition), and assigned an effectiveness rating for each mitigation at preventing each outage combination. The effectiveness rating describes how effective each of the mitigation alternatives would be in mitigating that type of outage combination.

Table PG&E 8.2.1-1 below shows examples to present how the basic cause of the event, plus three additional attributes (including the primary, secondary or service line equipment), combine and become a unique outage combination. The table includes eight examples, one for each of the eight basic causes of failure.

TABLE PG&E-8.2.1-1:
MITIGATION EFFECTIVENESS ASSESSMENT – FAILURE MODE EXAMPLES

Line No.	Basic Cause of a Failure/Outage	Supplemental Cause of a Failure/Outage	Failed/ Involved Equipment	Equipment Condition	Outage Combination
1	Third Party	Vehicle	Secondary	Broken, Wire on Ground	Third Party | Vehicle | Secondary | Broken Wire on Ground
2	Animal	Squirrel	Primary Overhead Conductor	Burned/ Flashed	Animal | Squirrel | Primary Overhead Conductor | Burned/Flashed
3	Company Initiated	Improper Construction	Primary Overhead Conductor	Deteriorated	Company Initiated | Improper Construction | Primary Overhead Conductor | Deteriorated
4	Environmental /External	Ice or Snow	Service Conductor	Broken, Wire on Ground	Environmental/External | Ice or Snow | Service Conductor | Broken, Wire on Ground
5	Equipment Failure/Involved	Other	Primary Fuse	Broken	Equipment Failure/Other | Primary Fuse | Broken
6	Unknown Cause	Patrol, Found Nothing	Primary Pole – Wood	Burned/ Flashed	Unknown Cause | Patrol, Found Nothing | Primary Pole – Wood | Burned/Flashed
7	Vegetation	Tree – Branch Fell on Line	Primary Anchor or Guy	Broken	Vegetation | Tree – Branch Fell on Line | Primary Anchor or Guy | Broken
8	Wildfire Mitigation	PSPS	Circuit Breaker	Normal	Wildfire Mitigation | PSPS | Circuit Breaker | Normal

We recognize that the number and location of outages varies and therefore we analyzed outages and mitigation effectiveness across ten years (2015-2024) within the HFTD areas.

<u>Incorporating Location-Specific Inputs into Wildfire Mitigation Effectiveness Calculations</u>

Table PG&E-8.2.1-2 continues the example analysis. The table includes three mitigations and a rating of how effective each would be at preventing ignitions from the eight example outage combinations shown above. The rating scale used in the effectiveness assessment is:

- *All: 100 percent effective – Assumes no ignition events;*
- *Very High: 90 percent effective – Assumes the mitigation addresses most ignition concerns, but still leaves a potential for ignition;*
- *High: 75 percent effective – Assumes the mitigation provides significant ignition reduction; however, there is still a chance for contact or failure;*

- *Medium High: 60 percent effective – More than likely ignition reduction for an event;*
- *Medium: 40 percent effective – Less probable ignition reduction for an event;*
- *Low: 10 percent effective – Some ignition reduction mitigation but not significant; and*
- *None: 0 percent effective – No protection against ignition.*

These average effectiveness ratings were developed based on a review of ten years of unplanned outage history between 2015 and 2024. This historical review differs from the methodology used to calculate the annual effectiveness reported by PG&E for any given year. The annual effectiveness calculation considers weighted frequency of ignition to outage whereas the historical effectiveness calculation does not. The purpose of the historical calculation is to analyze all known potential failure combinations whether or not they caused an ignition.

TABLE PG&E-8.2.1-2:
IGNITION MITIGATION EFFECTIVENESS RATINGS FOR EXAMPLE MITIGATIONS

Line No.	Outage combination	UG All	UG Primary	Overhead CC + EPSS	CC with PSPS and EPSS
1	Third Party I Vehicle I Secondary I Broken Wire on Ground	All	Medium	Medium	Very High
2	Animal I Squirrel I Primary Overhead Conductor I Burned/Flashed	All	All	Very High	All
3	Company Initiated I Improper Construction I Primary Overhead Conductor I Deteriorated[(a)]	N/A	N/A	N/A	N/A
4	Environmental/External I Ice or Snow I Service Conductor I Broken, Wire on Ground[(b)]	All	None	None	All
5	Equipment Failure/Other I Primary Fuse I Broken	All	All	Very High	All
6	Unknown Cause I Patrol, Found Nothing I Primary Pole – Wood I Burned/Flashed	All	All	Very High	All
7	Vegetation I Tree – Branch Fell on Primary Line I Anchor or Guy I Broken	All	All	Very High	All
8	Wildfire Mitigation I PSPS I Circuit Breaker I Normal[(a)]	N/A	N/A	N/A	N/A

(a) Line numbers 3 and 8 are marked N/A because PG&E-initiated outages were excluded from this mitigation effectiveness analysis because a PG&E-initiated outage would not cause an ignition.

(b) The outage combination in line 4 relates to a conductor on a service line. None of these mitigations involves secondary or service lines, and so this outage scenario would not be prevented by any of these mitigations.

After determining how effective each alternative mitigation would be at preventing an ignition based on the outage combination characteristics, PG&E uses this information to analyze circuit segment-level wildfire mitigation effectiveness of different mitigations or combinations of mitigations. To determine circuit segment-level mitigation effectiveness, the WBCA adjusts for ignition risk sub-drivers on a given circuit segment based on the WDRM, their estimated frequency, and their contribution to overall risk on the circuit segment.[73]

Table PG&E 8.2.1-3 presents the blended average effectiveness values for each of the five current alternatives PG&E anticipates analyzing in our WBCA. While five possible mitigations are presented in this table, these mitigations may not be applicable to every location. Because these values reflect the blended average effectiveness, they are not the exact number that will be applied to each distinct circuit segment in the WBCA. Instead, as described above, when analyzing a potential project, the WBCA uses specific effectiveness values for those circuit segments based on the unique risk sub-drivers (outage combinations) for that location, as identified by the WDRM.

TABLE PG&E-8.2.1-3:
IGNITION MITIGATION EFFECTIVENESS
REPRESENTATIVE BLENDED AVERAGE VALUES

System Hardening Scenarios	Blended Average Effectiveness[a]
Underground All (Underground Primary Lines, Secondary Lines and Services)	99%
Underground Primary Distribution Lines	98%
Line Removal w/ Remote Grid	98%
Covered Conductor with EPSS and PSPS[b]	97%
Covered Conductor with EPSS and DCD	79%
Covered Conductor	67%

Note: Assumptions – Analysis assumes no overhead degradation for life of the asset.

(a) This effectiveness evaluation is based on an assessment of each mitigation's prevention of an ignition from active faults of known cause on overhead assets. Company-initiated outages, including PSPS outages, outages of Unknown cause, as well as outages on existing underground assets are not applicable to this study and are excluded from calculation results as "N/A."

(b) The combined "Overhead with EPSS and PSPS" effectiveness differs from others in the table as it is the result of two independent studies. The first study yields PSPS effectiveness alone to be approximately 84 percent effective at mitigating wildfire risk. Subsequently, the combined effectiveness of approximately 79 percent for "Overhead with EPSS" is applied on top of the PSPS reduction, resulting in: Mitigation Effectiveness = 84% + (100% 84%) * 79% = 97%.

73 Risk sub-drivers are the various activities that PG&E groups under a risk driver. For example, lightening arrestor damage, switch failure and transformer failure are all sub-drivers grouped under the risk driver "equipment damage."

Impacts on the Likelihood of Ignitions

CC meaningfully reduces the likelihood of ignition risk from most equipment failure sub-risk drivers, vegetation contact, contact from object, unknown, contamination, other, wire-to-wire, and vandalism/theft. However, it does not fully eliminate the likelihood of ignition risk associated with any of the risk drivers.

Undergrounding primary distribution lines, secondary lines and services (undergrounding all) is the most effective way to mitigate against ignition risk. Undergrounding eliminates the likelihood of ignition risk from most of the risk drivers and sub-risk drivers shown in Table PG&E-8.2.1-4 below,[74] including: vegetation contact (the highest ignition risk driver); most of the equipment failure sub-drivers; most contact from object sub-drivers; contamination; wire-to-wire contact; other causes; and vandalism/theft. Undergrounding also significantly reduces the likelihood of ignition where we are unable to determine the cause of an ignition and reduces risk due to other equipment or facility failure and other object contact.

Undergrounding only primary distribution lines also effectively mitigates against ignition risk. It eliminates the likelihood of ignition risk from many risk drivers and sub-risk drivers, including most of the equipment failure sub-drivers and from contact due to animal and balloon contact. Undergrounding primary distribution lines meaningfully reduces or eliminates the likelihood of ignition from: other equipment or facility failure; vegetation contact; vehicle contact and other contact from object; contamination; wire-to-wire contact; vandalism/theft; and other causes.

Table PG&E-8.2.1-4 below shows how covered conductor, undergrounding primary, and undergrounding all lines impact the likelihood of ignition by risk driver. Terms used in Table PG&E-8.2.1-4 have the following meanings:

- All 100 Percent: The mitigation is 100 percent effective at reducing the likelihood of ignition risk due to the risk driver.
- Very High 90-99 Percent: The mitigation is 90-99 percent effective at reducing the likelihood of ignition risk due to the risk driver.
- High 70-89 Percent: The mitigation is 70-89 percent effective at reducing the likelihood of ignition risk due to the risk driver.
- Medium High 60-69 Percent: The mitigation is 60-69 percent effective at reducing the likelihood of ignition risk due to the risk driver.

74 Risk drivers are direct causes that lead to a risk event and indicate the likelihood or frequency of said risk event. Risk drivers include external events (such as vegetation contact) and characteristics inherent to the assets or systems (such as equipment/facility failure) which contribute to the risk event. Risk drivers can be broken into sub-drivers. For example, sub-drivers of the equipment/facility failure driver include conductor damage or failure, crossarm damage or failure, and pole damage or failure.

- Medium 40-59 Percent: The mitigation is 40-59 percent effective at reducing the likelihood of ignition risk due to the risk driver.
- Low 20-39 Percent: The mitigation is 20-39 percent effective at reducing the likelihood of ignition risk due to the risk driver.
- None 0-19 Percent: The mitigation is 0-19 percent effective at reducing the likelihood of ignition risk due to the risk driver.

TABLE PG&E-8.2.1-4:
COVERED CONDUCTOR AND UNDERGROUNDING IMPACTS ON THE LIKELIHOOD OF IGNITION

Risk Driver	Description	Covered Conductor with Enhanced Powerline Safety Setting and Downed Conductor Detection	Underground Primary	Underground Primary and Secondary Lines and Services (Underground All)
Equipment Failure	Events where failure of a PG&E asset, such as a conductor, arrester, insulator, breaker, transformer, etc., caused an ignition. This includes ignitions caused by wire-to-wire contact, commonly known as line slap.	Very High: The likelihood of ignition due to damage or failure of connection device, fuse, lightening arrestor, switch, and transformer High: The likelihood of ignition due to damage or failure of anchor/guy, crossarm, insulator and brushing, and pole damage. Medium High: The likelihood of ignition due to damage or failure of capacitor bank, recloser, and sectionalizer. Medium: The likelihood of ignition due to damage or failure of voltage regulator and secondary damage or failure.	All: The likelihood of ignition due to damage or failure of anchor/guy, capacitor bank, connection device, crossarm, fuse, insulator and brushing, lightning arrestor, pole damage, recloser, sectionalizer, switch, transformer, and voltage regulator. Very High: The likelihood of ignition due to damage or failure of conductor damage or failure. Medium High: The likelihood of ignition due to other equipment or facility failure. Medium: The likelihood of ignition due to secondary damage or failure.	All: The likelihood of ignition due to damage or failure of anchor/guy, capacitor bank, connection device, crossarm, fuse, insulator and brushing, lightning arrestor, pole damage, recloser, sectionalizer, switch, transformer, voltage regulator, and conductor. Medium High: The likelihood of ignition due to other equipment or facility failure. All: The likelihood of ignition due to secondary damage or failure.
Vegetation Contact	Events where trees, tree limbs, and other vegetation come in contact with a PG&E asset, resulting in an ignition.	High: Reduces the likelihood of ignition risk due to branch not overhanging, branch overhanging, dead vegetation, vegetation falling into, vegetation growing into, and other vegetation contact.	Very High: The likelihood of ignition risk due to branch not overhanging, branch overhanging, dead vegetation, vegetation falling into, vegetation growing into, and other vegetation contact.	All: The likelihood of ignition risk due to branch not overhanging, branch overhanging, dead vegetation, vegetation falling into, vegetation growing into, and other vegetation contact.

TABLE PG&E-8.2.1-4:
COVERED CONDUCTOR AND UNDERGROUNDING IMPACTS ON THE LIKELIHOOD OF IGNITION
(CONTINUED)

Risk Driver	Description	Covered Conductor with Enhanced Powerline Safety Setting and Downed Conductor Detection	Underground Primary	Underground Primary and Secondary Lines and Services (Underground All)
Contact from Object	Events where objects come into contact with PG&E line equipment and create an ignition. This includes animal/bird contact, mylar balloons, and vehicles.	High: The likelihood of ignition due to animal contact, ballon contact, and vehicle contact. Medium: The likelihood of ignition due to contact from object.	All: The likelihood of ignition due to animal and ballon contact. Very High: The likelihood of an ignition due to vehicle contact. High: The likelihood of ignition due to other contact from object.	All: The likelihood of ignition due to animal contact, ballon contact, and vehicle contact. High: The likelihood of ignition due to other contact from object.
Unable to Determine (Unknown)	Events associated with PG&E assets which led to an ignition, but where PG&E is unable to establish the main driver of the ignition.	High: The likelihood of ignition where PG&E is unable to determine the cause of an ignition.	Very High: The likelihood of an ignition where PG&E is unable to determine the cause of an ignition.	Very High: The likelihood of an ignition where PG&E is unable to determine the cause of an ignition.
Contamination	Events, including ignitions, caused by battery assets and contaminated insulators.	High: The likelihood of ignition due to contamination.	Very High: The likelihood of ignition due to contamination.	All: The likelihood of ignition due to contamination.
Other	Events without known causes.	Medium: The likelihood of ignition due to other causes.	Very High: The likelihood of ignition due to other causes.	Very High: The likelihood of ignition due to other causes.
Wire-to-Wire Contact	Ignitions caused by wire-to-wire contact, commonly known as line slap.	Medium: The likelihood of ignition due to wire-to-wire contact.	Medium: The likelihood of ignition due to wire-to-wire contact.	All: The likelihood of ignition due to wire-to-wire contact/contamination.
Utility Work/ Operation	Activities around utility processes.	None: The likelihood of ignition risk from utility work/operation.	None: The likelihood of ignition risk from utility work/operation.	None: The likelihood of ignition risk from utility work/operation.
Vandalism/ Theft	Vandalism from outside parties.	Medium High: The likelihood of ignition risk due to vandalism or theft.	Very High: The likelihood of ignition risk due to vandalism or theft.	All: The likelihood of ignition risk due to vandalism or theft.

Note: Updated based on Non-Substantive Errata filing on May 16, 2025 in accordance with Energy Safety issuance of Revision Notice at 21.

Risk Reduction Trends

For the two programs shown below in Table PG&E-8.2.1-5, the trend analysis for wildfire risk and outage program risk (PSPS, EPSS) is relative to the 2023 baseline. PG&E does not have the dataset to provide this same trend analysis going back prior to 2023. PG&E is developing methods for performing this analysis at the risk driver-level for covered conductor. For undergrounding, recognizing that effectiveness is 98 percent, the risk driver details are de minimis. Information for the remaining mitigation activities needed to complete this analysis is not available at this time.

TABLE PG&E-8.2.1-5:
COVERED CONDUCTOR AND UNDERGROUNDING RISK REDUCTION TREND ANALYSIS

Activity	2023 % Wildfire Risk Reduction	2023 % EPSS Risk Reduction	2023 % PSPS Risk Reduction	2023-2024 Cumulative % Wildfire Risk Reduction	2023-2024 Cumulative % EPSS Risk Reduction	2023-2024 Cumulative % PSPS Risk Reduction
Covered conductor Installation	0.25%	0.23%	–	0.36%	0.35%	–
Undergrounding of electric lines and/or equipment	0.64%	0.68%	0.83%	1.49%	1.20%	2.03%

Impacts on Likelihood and Consequence of Ignitions

Consequence of an ignition is driven by topography and fuels. PG&E does not primarily target consequence improvements when planning system hardening. Rather, the goal of the system hardening program is to reduce the likelihood of ignition because that is how system hardening activities provide significant benefit.

Impact of the Activity on Outage Program Risk

We address the expected percent outage program risk reduction/effectiveness for covered conductor and undergrounding in Section 6.2.1.2, Table 6-3.

We consider the status of upstream circuit segments when evaluating system hardening locations and selecting mitigations because that upstream hardened status affects the reliability effectiveness of the mitigation. In any given location, overhead hardening does not reduce the impact from PSPS events, but is expected to reduce EPSS-caused outages. Undergrounding a location can reduce or eliminate distribution PSPS events and eliminate EPSS-caused outages. However, reliability improvements from both overhead hardening and undergrounding may be lower if the upstream circuit segments are not overhead hardened or undergrounded.

As an example of how we consider this information, in areas subject to frequent PSPS events, we evaluate where weather polygons that designate the boundaries of PSPS events have historically been located and then determine if undergrounding upstream circuit segments would reduce or eliminate future distribution PSPS events.

Impacts on Likelihood and Consequence of Program Events

Our response is specific to likelihood of outage program events because system hardening impacts the likelihood of an outage program event occurring but does not impact the consequence of an event.

Regarding PSPS events, undergrounding impacts the circuit segments that are included in distribution PSPS events. To determine which circuit segments are included in a PSPS event, PG&E's meteorology team draws a polygon outlining the areas that will be impacted by the severe weather event. PG&E then determines which circuit segments inside the weather polygon will be disabled during the PSPS event. Undergrounded lines within the weather polygon do not need to be turned off during severe weather conditions where all of the connected circuit segments within the severe weather polygon are undergrounded. If overhead and underground lines are interconnected within the severe weather polygon, then the underground lines may still need to be de-energized during the PSPS event because they may not be able to be sectionalized from the overhead lines. Therefore, when evaluating which circuit segments should be considered for undergrounding, PG&E considers the relationship between overhead lines, underground circuit segments, and sectionalizing devices.

Regarding EPSS, both undergrounding and overhead hardening reduce the likelihood of an outage event due to EPSS, to varying degrees depending on the reason for the EPSS event. Undergrounding eliminates the vast majority of EPSS outage causes, including tree strike risk, which nearly eliminates the likelihood that an EPSS event would occur on an underground line. Overhead hardening can limit, but not eliminate, the likelihood of an EPSS-caused outage.

See Table PG&E-8.2.1-5 for a trend analysis on outage program risk reduction from covered conductor and undergrounding.

This activity is expected to improve overall reliability. PG&E is working to quantify exactly how much reliability has improved where we have existing covered conductor and undergrounded segments.

Updates to the Activity

CC Work Completed to Date

Since 2018, PG&E has installed approximately 1,230 miles of hardened overhead conductor, including approximately 145 miles in 2023 and 108 miles in 2024. These overhead hardened miles are associated with PG&E's System Hardening Target GH-12 (formerly Target GH-01).

After we filed our 2023-2025 Base WMP, we adjusted our system hardening portfolio in light of the CPUC's 2023 GRC decision to include more overhead system hardening and less undergrounding.

Redefining the WMP CC Initiative and Target

In the 2023-2025 Base WMP, the CC initiative (GH-01) included work associated with the system hardening program, including overhead covered conductor, system hardening undergrounding, and removal of overhead lines in HFTD, HFRA, or buffer zone areas. This initiative excluded any mileage being undergrounded and tracked separately as part of our Butte County Rebuild and other Community Rebuild efforts.

The CC activity and target have been updated for this 2026-2028 Base WMP and in response to the Revision Notice. The revised target for the 2026-2028 Base WMP is now GH-12 and includes work associated with overhead distribution hardening (CC installation) for base system hardening work, fire rebuild work, and other work, in the HFTD. Undergrounding work is no longer included in this activity or target. All undergrounding work remains tracked in Target GH-04. Line removal enabled by remote grid is tracked separately in Target GH-14.

Accounting for Future Grid Needs

PG&E's system hardening scoping process accounts for future grid needs and includes collaboration with distribution planning and operating engineers so we can ensure our project scoping reflects anticipated future growth and operational needs. Specifically, PG&E's planning and operating engineers are included throughout the review and approval process from when a project is first identified for possible grid system hardening to when the final job package is created and the project design is estimated for construction.

Compatible Initiatives

As shown in Table PG&E-8.2.1-4 above, PG&E uses CC in combination with PSPS, EPSS and DCD to increase ignition risk reduction effectiveness.

Please also see discussion in Section 6.1.3.1.

8.2.2 Undergrounding of Electric Lines and/or Equipment

Tracking ID: GH-04

Overview of the Activity

PG&E's Undergrounding activity is focused on mitigating catastrophic wildfire risk and outage reliability risk caused by distribution overhead assets. PG&E's Undergrounding target is GH-04 is shown in Table 8-1 above, and includes undergrounding taking place as part of System Hardening, and any other undergrounding work performed in HFTD, HFRA, Buffer Zone, or fire rebuild areas.

PG&E's undergrounding hardening targets (GH-04), excluding community rebuild undergrounding, are shown in Table 8-1 above and Risk Impact of Activities are shown in Table 6-3.

Program Description

Undergrounding is part of PG&E's System Hardening Program described in Section 8.2.1 and is a key element in PG&E's effort to minimize the growing wildfire risk in its service territory. The primary risks addressed by undergrounding are ignition from overhead electric distribution equipment and decreased system reliability due to the implementation of outage programs used to mitigate wildfire risk.

Undergrounding electric distribution system assets follows the same general process as most utility construction work and includes: (1) project scoping; (2) engineering and design; (3) material acquisition; (4) permitting and land rights; (5) construction; (6) quality controls and inspections; and (7) mapping, documentation, and closeout.

PG&E also conducts undergrounding activities in wildfire rebuild areas as described in Section 8.2.1; however, those activities are excluded from the GH-04 targets and will not count towards achievement of the GH-04 targets.

Distribution Underbuilds on Transmission Lines

PG&E identifies distribution miles in its long-term undergrounding portfolio that share a pole or other structure with transmission. While these distribution miles are considered high-risk miles, the transmission line in the same location may have a different risk profile and different feasible mitigations and may require a different approach. Differences in the risk profile can be due to inherent equipment design, and structural differences between the distribution and transmission lines. For example, compared to distribution lines, transmission lines typically are higher and further above vegetation, involve less equipment (e.g., no transformers or switches), and have longer spans. PG&E uses separate models to evaluate the wildfire risk from distribution and transmission lines, with each model designed to reflect the distinct risk factors for wildfire risk. Depending on the conditions in the field, the distribution underbuilt on transmission lines that are identified for hardening may be overhead hardened or undergrounded. PG&E describes its transmission mitigation activities in Section 8.2.4.

Project Selection

PG&E describes its methodology for selecting system hardening projects and mitigation solutions, including undergrounding, in Section 8.2.1.

PG&E intends to file an EUP after all EUP Guidelines are adopted by Energy Safety and the CPUC and anticipates transitioning the undergrounding program to the EUP by 2028. PG&E intends to adopt the EUP project selection approach when its EUP is approved.

Impact of the Activity on Wildfire Risk

The system hardening effectiveness values are presented in Table 8-1 above.

PG&E addresses the expected percent reliability risk reduction/effectiveness for system hardening activities in Section 6.2.1.2.

See Table PG&E-8.2.1-5 for a trend analysis on wildfire risk reduction from covered conductor and undergrounding.

Impacts on Likelihood and Consequence of Ignitions

As discussed in Section 8.2.1 above, undergrounding primary distribution lines, secondary lines and services (undergrounding all) is the most effective way to mitigate against ignition risk. Undergrounding eliminates the likelihood of ignition risk from most of the risk drivers and sub-risk drivers including: vegetation contact—the highest ignition risk driver; most of the equipment failure sub-drivers; most contact from object sub-drivers; contamination; wire-to-wire contact; other causes; and vandalism/theft.

Impact of the Activity on Outage Program Risk

We address the expected percent outage program risk reduction/effectiveness for covered conductor and undergrounding in Section 6.2.1.2, Table 6-3.

PG&E analyzed the reliability performance on sections of circuits where we performed System Hardening Undergrounding work in 2022 and 2023 to quantify overall improvements to service reliability. PG&E's analysis included approximately 750 outages between 2021 and 2024 and showed approximately a 90 percent reduction in faults that resulted in sustained outages after this undergrounding work was completed. See discussion in Section 8.2.1 above for a discussion of how the electrical corporation considers and evaluates the hardened status of upstream circuits/segments/spans to determine the impact of the activity on reliability risk.

See Table PG&E-8.2.1-5 for a trend analysis on outage program risk reduction from covered conductor and undergrounding.

Impacts on Likelihood and Consequence of Program Events

As discussed in Section 8.2.1 above, underground lines may be exempt from PSPS activity as they do not pose an ignition risk during the extreme weather conditions that drive PSPS events. However, whether an area would still be subject to PSPS events after lines in that area are undergrounded depends on whether, and how much, of the upstream and downstream line sections were undergrounded. For example, undergrounding may not eliminate PSPS risk for the customers directly connected to an underground section if that section remains connected to an overhead line (either upstream or downstream) that is subject to PSPS. While overhead hardening does not automatically exempt a location from a PSPS event, the hardened status of a line, and of any overhead upstream and downstream lines, is considered in the analysis that identifies the lines scoped into a PSPS event. As PG&E completes additional undergrounding, and underground sections are connected, more PSPS risk will be mitigated.

Updates to the Activity

Since 2019, PG&E has undergrounded approximately 924 miles of distribution line, including approximately 365 miles in 2023 and 258 miles in 2024. These miles are associated with PG&E's Undergrounding Activity GH-04.

Since filing our 2023-2025 Base WMP, we adjusted our system hardening portfolio in light of the CPUC's 2023 GRC decision to include more overhead system hardening and less undergrounding.

The underground activity and target have been updated in response to the Revision Notice requirement to exclude community rebuild work. Per RN-PG&E-26-05, the GH-04 target does not include community rebuild work, and any community rebuild miles will not count towards achievement of the target.

PG&E has not yet filed a 10-Year EUP Application, so the requirement for workplan and progress updates per Public Utilities Code section 8388.5(f)(2) is not applicable for this WMP.

Compatible Initiatives

Undergrounding distribution lines is effective at mitigating ignition risk. In certain circumstances (e.g., high wind events), PG&E uses undergrounding in combination with PSPS to account for adjacent distribution lines that have not been undergrounded.

Please also see discussion in Section 6.1.3.1.

8.2.3 Distribution Pole Replacements and Reinforcements

Tracking ID: N/A

Overview of the Activity

Distribution poles are inspected and evaluated to determine their condition to support pole mounted equipment and safely keep energized conductors in the air. When deterioration is detected, the distribution poles are remediated through replacement or reinforcement, which reduces the risk of ignition.

The Distribution Pole Replacement Program identifies poles for replacement when an existing pole is determined to be deficient because of degradation, overload, or other means. Poles are identified for replacement through various methods and criteria, including:

- Through routine inspections, which include patrols, detailed visual inspections, and intrusive inspections;
- When assessing the loading on the pole, through the pole loading assessment program, routine inspections, or when assessing the pole for planned work (i.e., transformer replacement, etc.);
- When the degradation is discovered above ground which includes the top of the pole (e.g., woodpecker damage) or a few feet above the ground (e.g., termites); and
- When mechanically overloaded and a larger pole is required to support the conductor and overhead equipment.

Since 2023, PG&E has bundled distribution pole replacements with non-pole maintenance tags to gain efficiencies and minimize customer impacts. The objective of the bundling program is to perform all the corrective maintenance (pole and non-pole) on the line segment under one clearance to maximize the risk spend efficiency.

The Distribution Pole Reinforcement Program provides life extension for existing poles by installing a steel truss at the base of the wood poles. Poles are tagged for reinforcement through routine intrusive inspections. Poles may be reinforced if the degradation is at or below ground level. To qualify for reinforcement, the pole must be in good health above ground to support the banding of the steel truss to the wood pole.

Impact of the Activity on Wildfire Risk

Distribution pole replacements and reinforcements reduce wildfire risk by decreasing the likelihood of premature pole failures. Pole failures can result in energized wires contacting the ground, which may cause an ignition.

Impact of the Activity on Outage Program Risk

The hardened status of upstream circuits/segments/spans does not impact the reliability risk of this activity.

The existence of open maintenance tags for electric assets, including distribution poles, is a factor in PSPS scope determination. Therefore, pole replacement and reinforcement may decrease the likelihood that the surrounding area would be subject to a PSPS event. However, areas where poles have been replaced or reinforced may still be subject to a PSPS event because open maintenance tags are not the sole factor in determining PSPS scope.

Pole replacement and reinforcement improves overall reliability by reducing the likelihood of outages associated with pole failures.

Updates to the Activity

We are improving the efficiency of our pole replacement process by creating more opportunities for bundling tags. See Section 8.6.2 for more information.

Distribution pole replacement and reinforcement focuses primarily on mitigation of ignition risk from asset failure and thus does not have any added benefits for future grid needs, such as load capacity, peak demand, and system flexibility.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used with programs such as Distribution Pole Replacements.

Please also see discussion in Section 6.1.3.1.

8.2.4 Transmission Pole/Tower Replacements and Reinforcements

Tracking ID: N/A

Overview of the Activity

This activity addresses remediation, adjustments, or installations of new equipment to improve or replace existing transmission wood poles and towers (e.g., structures such as lattice steel towers or tubular steel poles that support lines at transmission voltages). PG&E defines transmission voltages to be at or above 60 kV.

Maintenance, repair, life extension, and replacement of transmission structures in the HFTD are integral means of mitigating risk associated with wildfire. These activities help reduce the risk of failure, thus reducing ignitions and the likelihood of being included in PSPS events. In addition, repairing or replacing transmission structures generally increases public and employee safety and system reliability for our customers.

Transmission structure activities include the following:

- Transmission maintenance repair tags. Further information and the related target for this activity can be found in Section 8.6;
- Transmission tower coating is used on structures in areas subject to atmospheric corrosion;
- Transmission tower cathodic protection is used to control corrosion of the structure's metal surface;
- Wood pole reinforcement provides additional strength near the base of wood poles; and
- Transmission structure replacements are based on conditions where repairs or life extension would not be as effective. Replacement structures are typically constructed to more robust, current design standards.

Impact of the Activity on Wildfire Risk

Transmission structure replacements and reinforcements reduce wildfire risk by decreasing the likelihood of asset failure (which could lead to ignition). Specifically replacing wood poles with steel reduces the ignition likelihood of energized components in contact with the structure or a path to ground. Other factors, such as the newer age of replaced equipment, may also reduce the risk of asset failure. Risk reduction/effectiveness can vary depending on location and type of mitigation used for pole/tower replacement and reinforcement. Please see Section 5.2 for more information on the Wildfire Transmission Risk Model (WTRM).

Impact of the Activity on Outage Program Risk

Reduced wildfire risk reduces outage risk since probability of failure is reduced upon replacement or reinforcement of the asset. Asset probability of failure is determined and utilized in both the WTRM and Operability Assessment (OA) models. The OA model is a factor in PSPS scope determination. See Section 11.2.1 with more detail available in PG&E’s CERP and PSPS Annex, and Section 5.2 for information on the risk model. Risk reduction/effectiveness can vary depending on location and type of mitigation used for pole/tower replacement and reinforcement.

Since transmission line PSPS scoping includes additional factors beyond pole and tower asset failure probability (such as vegetation risk), an area could still be subject to PSPS events after poles and towers are replaced or reinforced.

Updates to the Activity

Going forward, continued wood to steel replacements are expected. This activity is included as part of the larger maintenance program described in Section 8.6.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. Additional programs used in combination with Transmission Pole/Tower Replacements and Reinforcements include: Traditional Overhead Hardening – Transmission Conductor (Section 8.2.5); Routine Patrol Transmission (Section 9.2.3); Protective Equipment and Device Settings (Section 8.7.1.1); and Transmission Avian Mitigation – Di-electric Cover Pilot (Section 8.2.13.1).

8.2.5 Traditional Overhead Hardening

8.2.5.1 Traditional Overhead Hardening – Transmission Conductor

Tracking ID: GH-06, GH-11

Overview of the Activity

Traditional overhead hardening of transmission conductor can occur through asset replacement and maintenance programs, described in Section 8.4. Additionally, there may be programs that specifically target reducing transmission line conductor failures that may lead to wildfire ignition. These activities include Dispersed Conductor (Splice) Hardening and Conductor Segment Replacements.

<u>Dispersed Conductor Component (Splice) Hardening</u>

A conductor splice is a point of potential failure within a conductor span. A shunt splice is applied directly over the existing splice and extends some distance on either side of the splice. The installation of a shunt splice on top of the existing splice eliminates the splice as a single point of failure because with the shunt, a failure of the original splice would not result in a downed conductor. Lines prioritized for this program are based on higher risk splice and wildfire consequence. Shunt splice installation is represented by Target GH-06 in Section 8.1.

Conductor Segment Replacements

This activity reduces risk by replacing a segment where the conductor segments are at higher risk, but the supporting structures are in good condition and there is no additional electrical capacity need to increase the conductor size. Conductor segment risk is assessed with the WTRM. Target Conductor segment replacements on transmission lines traversing HFTD/HFRA areas are represented by Target GH-11 in Section 8.1.

Impact of the Activity on Wildfire Risk

Transmission shunt splice installations and segment replacements are done at the line level, within HFTD. Replacement or reinforcement of conductor in the HFTD reduces wildfire risk by decreasing the likelihood of asset failure. Other factors, such as the newer age of replaced equipment, may also reduce the risk of asset failure.

Impact of the Activity on Outage Program Risk

Generally, lines that have been hardened against conductor failure via replacement or reinforcement are more robust and less likely to fail. Newer assets will be up to current standards, less likely to be impacted by vegetation or other hazards.

Since transmission line PSPS scoping includes additional factors beyond just conductor failure probability (such as vegetation risk), an area could still be subject to PSPS events after assets are hardened against conductor failure. Asset probability of failure is determined and utilized in both the WTRM and OA models. The OA model is a factor in PSPS scope determination. Please see Section 11.2.1 with more detail available in PG&E's CERP and PSPS Annex, and Section 5.2 for information on the risk model.

The activity can reduce reliability risk as transmission lines are upstream of the distribution system and the interconnected customers. Hardening the transmission lines thus improves the reliability of the distribution system.

Updates to the Activity

There are no updates since the 2023-2025 WMP.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used alongside Traditional Overhead Hardening – Transmission Conductor. Additional programs used in combination with alongside Traditional Overhead Hardening – Transmission Conductor include: Transmission Pole/Tower Replacements and Reinforcements (Section 8.2.4); Routine Patrol – Transmission (Section 9.2.3); Protective Equipment and Device Settings (Section 8.7.1.1); and Equipment Maintenance (Section 8.4).

Please also see discussion in Section 6.1.3.1.

8.2.5.2 Traditional Overhead Hardening – Distribution

PG&E does not have a separate activity for distribution overhead system component hardening that aligns with Energy Safety's definition of traditional overhead hardening.

See Section 8.4 for more information on PG&E's Asset Replacement and Maintenance programs.

8.2.6 Emerging Grid Hardening Technology Installations and Pilots

8.2.6.1 Distribution, Transmission, and Substation: Fire Action Schemes and Technology

Tracking ID: N/A

Overview of the Activity

Distribution, Transmission, and Substation-Fire Action Schemes and Technology (DTS FAST) is a technology PG&E designed to enhance wildfire risk mitigation by instantaneously identifying contacts with power lines by foreign objects. The activity is a pilot. The technology utilizes advanced, fraction-of-a-second detection systems to identify objects, such as falling or leaning vegetation encroaching on energized power lines and rapidly shuts off power before impact. Additionally, DTS FAST can detect elevated fire risk conditions associated with energized power lines, enabling rapid power shutdowns in scenarios such as downed power lines, leaning or fallen towers and poles, and equipment failures. At the time of this filing, DTS FAST is in the pilot phase.

DTS FAST was installed on a total of four towers: Oleum Martinez 115 kV Towers 044, 045, and 046 in 2020, and then Salt Springs 115 kV Tower 026 in 2023. No ignitions have occurred at these locations since DTS FAST was installed.

Impact of the Activity on Wildfire Risk

DTS FAST has the potential to reduce the occurrence of ignitions by rapidly shutting off power before an object can impact an energized powerline and cause an ignition. However, at the current stage of the pilot, the maturity of the technology and the system is being monitored before any risk reduction calculations are published.

Impact of the Activity on Outage Program Risk

The hardened status of upstream circuits/segments/spans does not impact the reliability risk of this activity.

This activity does not impact the likelihood or consequence of outage program events and would not affect whether an area is subject to PSPS events. This is because the activity is intended to deactivate the line in the event that an object is going to contact the line, resulting in deactivation. For this reason, the activity does not impact overall system reliability.

Updates to the Activity

No new DTS FAST projects are currently planned. PG&E continues to monitor the operational reliability of the pilot at existing installed locations.

DTS FAST focuses primarily on ignition risk elimination and thus does not have any added benefits for future grid needs, such as load capacity, peak demand, and system flexibility.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used alongside Distribution, Transmission, and Substation: Fire Action Schemes and Technology.

8.2.7 Microgrids

8.2.7.1 Remote Grids

Tracking ID: GH-14

Overview of the Activity

Remote Grids provide utility service to small loads in remote locations at the outskirts of the distribution system, in lieu of traditional wires. Throughout PG&E's service territory, pockets of small customer loads are served via long electric distribution feeders, some of which traverse HFTD areas or require significant annual maintenance and vegetation management. Remote Grids can be an alternative to system hardening solutions. The activity aims to remove distribution feeders and serve customers from a Remote Grid when that is the most cost-effective way to reduce risk.

The Remote Grid facilities include a Standalone Power System (SPS) consisting of local sources of electricity supply (typically a solar array, a battery, and a back-up generator) and utility infrastructure to continuously serve the electricity to the load. Following the installation of the facilities, the service from the broader grid is cut and the existing power lines are removed. PG&E has had sufficient experience with remote grids and now considers this as an activity within the broader system hardening efforts. However, the Remote Grid Program is still technically a pilot in accordance with Resolution (Res.) E-5132, where the Commission designated the program as a pilot subject to a cap of two megawatts of total customer load.

Line removal mileage enabled by Remote Grid is target GH-14. Since this activity is a key element of our overhead hardening activities, Section 8.2.1 contains additional relevant information on this work, where applicable.

Impact of the Activity on Wildfire Risk

Deploying a remote grid and removing the overhead line that previously served that customer load can reduce fire ignition risk, as an alternative to, or in conjunction with, system hardening or other risk mitigation efforts. Removing overhead lines in HFTD areas eliminates the risk of ignition that was previously associated with the overhead line.

Impact of the Activity on Outage Program Risk

The hardened status of upstream circuits/segments/spans does not impact the reliability risk of this activity because electric service is no longer dependent on upstream lines after a remote grid is installed. The Remote Grid Program, like the Undergrounding Program, includes removal of the overhead powerline. Locations with Remote Grids are descoped from PSPS events. However, due to the relatively small number of customers served by the Remote Grid Program, there is no significant impact on the broader measures of PSPS mitigation efforts.

Customers served by Remote Grids are no longer subject to outages caused by weather, tree strikes and impacts to the overhead distribution circuit that served them previously. Overall reliability for the customers served by Remote Grids was 99.7 percent in 2023 and 99.83 percent in 2024.

Updates to the Activity

PG&E plans to continue the Remote Grid Program in its current form.

Since the last WMP submission, PG&E has integrated Remote Grid monitoring with our core operational systems (SAP, EDGIS, Outage Management Tool, Hazard Awareness and Warning Center). Operational system integration enables faster response and restoration to outages, as well on-going asset management with PG&E's existing systems.

We have also developed Emergency Action Plans and posted them at all Remote Grids to provide first responders with the information necessary to interact safely with the system in adverse conditions.

The Remote Grid activity scoping process accounts for future growth at that location. This process includes collaboration with distribution planning and operating engineers so we can ensure our scoping reflects anticipated future growth and operational needs.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used alongside Remote Grids. Line Removal (Distribution) is also a compatible initiative to Remote Grid (Section 8.2.9.2).

8.2.7.2 Temporary Distribution Microgrids

Tracking ID: N/A

Overview of the Activity

Temporary distribution microgrids are designed to support community resilience and reduce the number of customers impacted by PSPS by energizing "main street corridors" with clusters of shared services and critical facilities so that those resources can continue serving surrounding residents during PSPS events. Though each temporary distribution microgrid (DMG) varies in scale and scope, the following design features are likely for each:

- Devices used to disconnect the DMG from the larger electrical grid include:
  - A pre-determined space for backup generation and equipment to allow for rapid connections (e.g., Pre-installed Interconnection Hubs (PIH)); and
  - The use of temporary generators that allow PG&E to shorten the design and construction time required to ready a permanent microgrid for operation.

Impact of the Activity on Wildfire Risk

The deployment of microgrids does not impact wildfire risk. Microgrids are deployed to support reliability during a PSPS event.

Impact of the Activity on Outage Program Risk

The existence of a temporary microgrid eliminates the reliability risk of a PSPS event for those customers who are included in the microgrid. We calculate customer minutes avoided to measure the impact of microgrids on reliability. All temporary microgrids on the system have been used to mitigate PSPS events at least once, some multiple times.

For each PSPS event outage, risk reduction was 100 percent for included customers. For example, during the 2024 PSPS season the Angwin temporary DMG was utilized for two separate PSPS events that equated to 305,000 customer minutes avoided from de-energization. See Table PG&E-8.2.7.2 below for the number of impacts avoided after temporary microgrid deployment over a 10-year period (2014-2023):

TABLE PG&E-8.2.7.2:
PSPS IMPACTS AVOIDED AFTER TEMPORARY MICROGRID DEPLOYMENT

DMG	Number of Impacts	Number of Customers[(a)]
Angwin	17	48
Magalia	13	37
Shingletown	11	69
Pollock Pines	8	44
Arnold	7	87
Foresthill	7	12
Georgetown	7	98
Calistoga	3	1,622
Colfax	2	366
Lucerne	2	666
Groveland	1	64
Middletown	1	436
North Clearlake	1	2,410

(a) Indicates the number of customers energized by the microgrid each time it was operated.

When considering where to locate the temporary microgrids, we evaluate the hardening status of the upstream assets because lines that are frequently subject to PSPS have reliability impacts. To the extent upstream hardening activities minimize or eliminate those assets being subject to PSPS, the need for the temporary microgrid to reduce reliability risk is lessened.

The temporary DMG program includes 12 microgrids that, if in scope, can mitigate power outages to main street corridors and provide critical services to communities during PSPS events. Critical facilities may include fire stations, police stations, grocery stores, medical facilities, gas stations, etc.

As discussed above, for those customers interconnected to the microgrid, reliability risk from PSPS is eliminated. The existence of a temporary microgrid however, does not influence the criteria for initiating a PSPS event.

Updates to the Activity

No additional temporary DMG PIH are planned in 2026 to 2028 and all previously planned microgrid sites are fully operational. PG&E may develop other distribution microgrids supported by temporary or permanent generation through other programs described in Section 8.2.7.3.

The Calistoga Temporary Microgrid will end after the Calistoga Clean Substation Microgrid (CSM) pilot comes online, which, at the time of this filing, is expected in June 2025 (See Section 13.3, Table PG&E-13.3-1: Completed WMP Activities). Following this, the total active temporary microgrids will drop from 13 to 12. For more information on the Calistoga CSM pilot, see Section 8.2.7.4.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used alongside Temporary Distribution Microgrids.

Please also see discussion in Section 6.1.3.1.

8.2.7.3 Community Microgrid Enablement Program and Microgrid Incentive Program

Tracking ID: N/A

Overview of the Activity

The Community Microgrid Enablement Program (CMEP) and Microgrid Incentive Program (MIP) support and provide incentives for the development of community-led multi-customer microgrids.

The CMEP, which launched in April 2021, helps communities with the technical, financial, legal, and regulatory challenges inherent in novel microgrid technology deployments, especially front-of-the-meter, multi–customer microgrids.

The CMEP consists of four elements:

1) Web-Based Tools and Information: PG&E provides financial, technical, and interconnection resources for community microgrid projects. See, for example, www.pge.com/cmep and PG&E's Community Microgrid Technical Best Practices Guide.[75]

2) Enhanced Utility Technical Support: PG&E provides incremental support to facilitate development of multi-customer microgrids from initial concept exploration, through assessment, and execution.

3) Pro Forma Tariff and Agreements: PG&E uses pro forma tariffs and agreements to administer the program. In 2020 PG&E developed a pro forma Community Microgrid Enablement Tariff (CMET) to govern the eligibility, development, island and transitional operation of community microgrids. PG&E has also developed a Microgrid Operating Agreement, which defines the roles and responsibilities in the development and operation of a community microgrid.

4) Cost Offsets: PG&E will offset the cost to design and deploy equipment needed to enable the safe islanding of a community microgrid of up to $3 million per project. This may include equipment such as isolation devices, PG&E's microgrid controller, and equipment to ensure that the microgrid is safe to operate. The cost offsets do not cover the cost of distributed generation or energy storage.

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75 The supporting document is available at: PG&E's Community Wildfire Safety Program.

The MIP is used to fund clean community microgrids, with a focus on critical energy needs of disadvantaged and vulnerable populations impacted by grid outages. The CPUC allotted a $200 million budget to MIP, of which PG&E was allocated $79.2 million. The program uses a scoring system based on customer resilience, and environmental benefits to award funding to selected projects.

Impact of the Activity on Wildfire Risk

In order for CMEP or MIP microgrids to operate during PSPS outages, some microgrids may need to underground circuits running through Tier 2 and 3 HFTD in addition to meeting other operational parameters. PG&E requires all circuits running through a Tier 2 or 3 HFTD to be undergrounded to operate safely if a PSPS weather polygon is directly over the microgrid footprint. Some communities may choose to cover the cost of undergrounding Tier 2 and 3 lines to ensure CMEP or MIP microgrids can operate during PSPS events, but others may find the cost prohibitive and choose not to underground, and therefore not be able to operate during direct PSPS events. This undergrounding activity would result in reduced wildfire risk. Until projects are identified and further designed, it cannot be determined what impact these programs may have on reducing wildfire risk at this time.

Impact of the Activity on Outage Program Risk

By providing support for community-led multi-customer microgrids, CMEP and MIP reduce overall outage risks on communities. The programs support the development of local community microgrids, which can provide energy resilience during PSPS or other outage events. Until projects are identified and further designed, it cannot be determined what impact these programs have on outage risk at this time. Each microgrid will also be uniquely designed in respect to the types of outage events the microgrid can provide energy resilience for, and therefore, the overall outage risk benefit.

Updates to the Activity

PG&E's MIP Handbook includes information about program requirements, the application process, and what is entailed for the design and development of a community microgrid.

Following the publication of the MIP Handbook[76] in October 2023, PG&E opened its first application window for communities to apply for MIP funding. PG&E received 47 initial consultation requests from communities interested in applying and received 22 completed applications by our July 2024 deadline. PG&E intends to hold a second application window starting in 2025.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used alongside CMEP and MIP. Vehicle to Everything Pilot

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76 The supporting document is available at: PG&E's Community Wildfire Safety Program.

(V2X Microgrid Pilot) is also a compatible initiative with CMEP and MIP (Section 8.2.9.2).

Please also see discussion in Section 6.1.3.1.

8.2.7.4 Microgrid–Related Technology Pilots

Tracking ID: N/A

Overview of the Activity

PG&E has initiated an evaluation of a variety of technology-driven pilot programs to potentially help mitigate the risk of wildfires and PSPS events. A description of key pilot programs follows.

Mobile BESS Development

The Mobile Battery Energy Storage System (BESS) Development pilot discussed in our 2023-2025 WMP is complete. See below for updates to the activity.

Vehicle Grid Integration (VGI) Microgrid Pilot #3

As part of the VGI Decision,[77] PG&E plans to test vehicle-to-grid technology to support resiliency in multi-customer PSPS impacted microgrids. The CPUC has opened up the pilot to single-customer microgrids in critical infrastructure. We began testing this capability on vehicle-to-grid chargers installed within PSPS microgrids in 2023 and plan to complete testing in 2025.

Calistoga Clean Substation Pilot

The Calistoga Clean Substation Microgrid (CSM) will be a highly innovative, renewable energy microgrid to mitigate PSPS outages using green hydrogen fuel cells and a BESS. Unlike the traditional use of mobile diesel generators to provide backup power at substations, this CSM is expected to have limited operating emissions of greenhouse gases (GHG) and other local air pollutants, while still meeting all operating and cost containment requirements for substation microgrids. The Calistoga CSM, when successfully developed, will represent a major advance in microgrid development and a significant step toward cleaner forms of microgrid generation.

Impact of the Activity on Wildfire Risk

The Calistoga CSM project is not expected to reduce the risk of wildfires within the HFTD area; the microgrid boundary that is energized by this microgrid is fully within a non-tiered HFTD area. The microgrid will provide energy resilience to downtown Calistoga and the surrounding area during times when this community is impacted by a PSPS outage and it is safe to energize the area within the microgrid boundary.

77 D.20-12-029. See Appendix E.

Impact of the Activity on Outage Program Risk

When considering where to locate microgrids, we evaluate the hardening status of upstream assets because lines that are frequently subject to PSPS have reliability impacts. To the extent upstream hardening activities minimize or eliminate those assets being subject to PSPS, the need for the microgrid to reduce reliability risk is lessened.

The Calistoga CSM Project will eliminate the reliability risk of a PSPS event for those customers who are included in the microgrid. For each PSPS outage event, risk reduction is expected to be 100 percent for included customers.

Both the Calistoga CSM project and VGI Microgrid technology pilots support the development of alternative microgrids, which can provide energy resilience during PSPS or other outage events and reduce impacts on communities.

The Calistoga CSM project specifically addresses PSPS events in the Calistoga area. The microgrid will serve customers located in the non-tiered HFTD zone of downtown Calistoga and the surrounding area when the Calistoga substation is impacted by a PSPS event and it is safe to energize the area within the microgrid boundary. While the microgrid project will not address general reliability issues on the Calistoga 1101 and 1102 circuits, it will reduce the impact of PSPS events on portions of these circuits—specifically, the portions of the circuit within the microgrid boundary.

The VGI Microgrid pilot will not directly impact the likelihood and consequence of PSPS or unplanned outage events.

Updates to the Activity

<u>Mobile BESS Development</u>

PG&E tested the Tesla Megapacks and support equipment required to supply power as grid forming or grid following sources at primary and secondary voltages. One unit has been tested and utilized for PSPS support at our Foresthill temporary DMG, and three units are planned for a reliability project in 2025.

<u>Calistoga Clean Substation Pilot</u>

PG&E issued a successful Request for Offers for the CSM pilot, resulting in a signed contract that was approved by the CPUC in May 2023. Project development began shortly thereafter. Currently, the projected online date is in June 2025.

<u>Vehicle Grid Integration (VGI) Microgrid Pilot #3</u>

PG&E has selected the Redwood Coast Airport Microgrid (RCAM) for Phase I of the VGI Microgrid Pilot. Four 20kw bi-directional electric vehicle chargers have been installed behind the meter at the airport with an estimated energization date of March 2025.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used alongside Microgrid Related Technology Pilots. The VGI Pilot is also compatible with CMEP and MIP (Section 8.2.7.3).

8.2.8 Installation of System Automation Equipment

8.2.8.1 Installation of System Automation Equipment – Distribution Protective Devices

PG&E installs distribution protective devices through our EPSS Program to provide enhanced capability to mitigate ignition risk, as well as improve reliability and reduce customer outage impacts.

EPSS is designed to protect beyond fuses and provide ganged operation, thereby reducing back-feed risk. We replace certain fuse protective zones with Line Reclosers (LR) and Fuse Savers to provide the same ignition reduction benefits but with fewer customers impacted if an outage occurs on the downstream sections.

After completing installations of distribution protective devices in the highest-impact locations in 2023 for our 2023-2025 WMP target, GH-07, we incorporated this activity into our base reliability work. See Table PG&E-13.3-1.

8.2.9 Line Removal (in the HFTD)

8.2.9.1 Line Removal (in the HFTD) – Transmission

We investigate potential HFTD idle facilities and, when these facilities are identified and no longer have future operational need, they are assessed for de-energization, grounding, and/or removal.

Identified transmission line removals in HFTD areas have been completed as of 2024. However, additional program work may be incurred during the 2026-2028 period. For more information and lessons learned, see Table 13-2: Lessons Learned from Discontinued Activities.

8.2.9.2 Line Removal (in the HFTD) – Distribution

Tracking ID: N/A

Overview of the Activity

Line removal is considered where a line is no longer needed for operational reasons due to one of the following reasons:

1) Idle Facilities: Known or suspected idle facilities that are not currently serving customer load; Primary conductor removal through the idle facilities program in HFTD are not part of targeted system hardening work and are not included in system hardening initiative targets; idle facilities removal is emergent work, identified during system inspections, and appropriately prioritized and addressed as part of PG&E's tag reporting and commitments when idle facilities are in an HFTD area (compliance MAT 2AF);

2) Circuit Re-Route: Rearrangement or re-alignment of the existing overhead circuit path to serve customers through an alternate route. Circuit re-routing line removal miles are not a targeted mitigation but instead are an incidental outcome of scoping for targeted overhead and underground hardening when there is re-routing involved;

3) Remote Grid: A Remote Grid, as discussed in Section 8.2.7.1, can result in existing assets no longer being operationally necessary and thus eligible for removal due to site or customer factors. Line removal enabled by remote grid is captured in GH-14.

Impact of the Activity on Wildfire Risk

Line removal results in 100 percent reduction of ignition risk associated with that line, specifically for equipment and conductor. Line removal is the preferred method for risk reduction and is considered for all system hardening locations where feasible. See Section 8.2.7.1 for information on the wildfire risk impact of remote grid after the line is removed.

Impact of the Activity on Outage Program Risk

Line removal has minimal impact on outage program risk because it is focused on lines that do not carry load. See Section 8.2.7.1 for information on the outage program risk impact of remote grid after the line is removed.

The removal of an overhead distribution line can help mitigate or reduce the size and impact of a PSPS event because potentially impacted customers would be served through an alternate method.

Updates to the Activity

It is difficult to anticipate future updates to the activity because line removal projects are difficult to forecast for four reasons: (1) customers considering a remote grid project may prefer wired service and try to decline the line removal option; (2) it is difficult to quantify the number of customers that will return to their homes and request service as part of a fire rebuild project that affects the number of service lines that will either be rebuilt or removed in fire rebuild areas; (3) idle facility line removal is an emergent issue driven by inspections and customer investigations each year; and (4) PG&E looks for opportunities to remove lines that are coincident/dependent with other hardening work.

See Section 8.2.7.1 for more information about how PG&E scopes for future growth when installing a remote grid when a line is removed.

Compatible Initiatives

Remote Grid is a compatible initiative to line removal. See Section 8.2.7.1 for more information.

8.2.10 Other Grid Topology Improvements to Minimize Risk of Ignitions

8.2.10.1 Downed Conductor Detection Devices

Downed Conductor Detection (DCD) is a component of EPSS that adds an additional protection element to address fault types not fully mitigated through the EPSS Program. DCD does this by enhancing the ability to quickly detect and de-energize low and very low initial current (high-impedance) line-to-ground faults before an ignition can occur.

PG&E plans to make capable the remaining DCDs in 2025 to complete our 2023-2025 WMP target, GM-06. At present, we have installed as much of the DCD hardware as possible. Please see Section 8.7.1.1 for more information on our EPSS Program.

8.2.10.2 Installation of System Automation Equipment – Installation of Devices to Eliminate High Impedance Back-feed Conditions

Fuse Saver installations mitigate against fire risk associated with downed wire events on tap line through ganged operated de-energization preventing certain types of high impedance faults from occurring. Fuse Savers are flexible, cost-effective, intelligent devices that can replace fuses and trip all phases (i.e., open and stop power flowing through all two or three phases if just one phase experiences a fault). Fuse Savers reduce the risk associated with a wire down event where the downed wire could remain energized due to a back-feed condition from another phase of the circuit.

After completing installations of Fuse Savers in the highest-impact locations in 2024, we incorporated this activity into our base reliability work. See Section 13.3, Table PG&E-13.3-1.

8.2.10.3 Motor Switch Operator Switch Replacement

Motor Switch Operator (MSO) switches were initially installed on PG&E's distribution system in mid-2019 as sectionalizing devices with the ability to reduce the scope of PSPS events. PG&E halted further installations of MSO switches in late 2019 after some MSO switches were reported to exhibit an arc flash during operation despite these switches being understood to meet exempt criteria. PG&E initiated a program to remove the MSO switches and replace them with alternative equipment that is approved for current usage in the HFTD.

In 2024, PG&E finished replacing all known MSO switches that were located within the HFTD or HFRA or were energizing lines that feed into the HFTD or HFRA for our 2023-2025 WMP target, GH-09.

Should we find additional MSOs, we will promptly replace them; however, this WMP activity is considered complete, and we do not expect any work for this activity in 2026 through 2028. See Section 13.3, Table PG&E-13.3-1.

8.2.10.4 Surge Arrester

The Surge Arrester Program replaces existing non-exempt surge arresters with exempt surge arresters at locations with potentially deficient grounding. Exempt surge arresters have less ignition risk. When the surge arrestor is being replaced, we also address common grounding by separating out the grounding on poles where surge arresters and transformers were co-located and shared a single ground. By separating the grounds, there are now two grounds, one for the surge arresters and one for the transformers.

PG&E met its target for surge arrestor removals for GH-08 in 2023, and with completion of the remaining remediation work on identified surge arrestors in 2024, the removal of the known population of non-exempt surge arresters with grounding issues in HFTD and HFRA areas is complete. Should we find additional non-exempt surge arrestors, we will promptly replace them. See Section 13.3, Table PG&E-13.3-1.

8.2.10.5 Non-Exempt Expulsion Fuses

This program reduces the consequence of potential ignitions by replacing and/or removing non-exempt fuses. The replacement of non-exempt equipment with exempt equipment reduces ignition risk because the exempt equipment does not generate arcs and/or sparks during normal operation.

PG&E plans to complete the remaining known population of non-exempt expulsion fuse removals in 2025 for our 2023-2025 WMP target GH-10, we do not expect any work for this activity in 2026 through 2028. Should we find additional non-exempt expulsion fuses, we will promptly replace them. See Section 13.3, Table PG&E-13.3-1.

8.2.10.6 Service Breakaway Connector Program

Tracking ID: GM-14

Overview of the Activity

In targeted areas with high risk of vegetation contact, PG&E installs Service Breakaway disconnects and replaces the corresponding service drop conductors and connectors on unhardened overhead services. This activity mitigates against ignition risk associated with arcing on service drops, which is often caused by vegetation contacting service wire. Service breakaways mitigate ignition risk through a separable link, which allows the service break to safely de-energize before it falls to the ground.

Service breakaways were approved for use by PG&E's standards organization in 2023. To date, they have most often been implemented in system hardening projects, and to a lesser extent, in restoration work.

Impact of the Activity on Wildfire Risk

The installation of service breakaway connectors mitigates the risk of arcing that can lead to ignitions. This activity is expected to reduce ignitions associated with service drops, frequently caused by vegetation fall-ins, by arcing at connections or between neutral and hot leg wires. In cases where vegetation falls into a service wire, service breakaways use a separable link to safely de-energize the service before it falls to the ground.

Impact of the Activity on Outage Program Risk

The hardened status of upstream circuits/segments/spans does not impact the reliability risk of this activity. This activity does not impact the likelihood or consequence of PSPS events.

This activity primarily focuses on mitigating ignition risks and has minimal impact on overall reliability. Outages that originate at service drops do not generally impact the secondary or primary upstream circuits; therefore, the only reliability impact would be on the customer being served. The service breakaway would not prevent an outage during a vegetation fall-in event, but it would ensure that the conductor falls safely to the ground, deenergized. It will, however, be faster to repair and return the customer to service.

Updates to the Activity

Breakaway connector installation is a new program and there are no additional updates.

Breakaway Connector focuses primarily on mitigation of ignition risk from asset failure, and thus, does not have any added benefits for future grid needs, such as load capacity, peak demand, and system flexibility.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used alongside Other Grid Topology Improvements to Minimize Risk of Ignitions.

8.2.11 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events

8.2.11.1 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Transmission

PG&E previously installed sectionalizing devices on our transmission system to allow us to segment the transmission circuits traversing HFTD areas.

PG&E completed installations of transmission sectionalizing devices to minimize customer impact from PSPS in 2022, and the mitigation initiative was discontinued in 2023, due to lack of incremental benefit. See Section 13.3, Table PG&E-13.3-1.

8.2.11.2 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Distribution

This program installs remotely operable Supervisory Control and Data Acquisition (SCADA) sectionalizing devices and manually operated sectionalizing devices on the distribution system to support PG&E's ability to segment the distribution circuits close to designated meteorology shut off polygons to reduce customer impact and scope of PSPS events.

After completing installations in the highest-impact locations on the distribution system in 2023, we incorporated this activity into our base reliability work. See Section 13.3, Table PG&E-13.3-1.

8.2.11.3 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Substation

Substation activities that enable the reduction of PSPS impacts include the installation or upgrade of protection equipment and automatic sectionalizing devices inside substations. This improves operating flexibility, thereby minimizing the scope and duration of PSPS events, as well as reducing equipment failure and ignition risks.

In 2022, PG&E used the 10-year PSPS lookback dataset to identify substations most likely to be impacted by PSPS events. PG&E identified and executed an upgrade from transformer primary fuse protection to circuit switcher and relay protection devices for transformer bank #1 at the Rincon substation. The most recent review of the lookback data set did not drive any upgrades. The 10-year lookback is updated annually and may drive adjustment to the program in future years. See Section 13.3, Table 13-3-1.

8.2.12 Other Technologies and Systems Not Listed Above

8.2.12.1 Substation Animal Abatement

Tracking ID: N/A

Overview of the Activity

The Substation Animal Abatement activity focuses on mitigating avian and ground animal-related contact events within substations and power generation switchyards with operating voltages of 34.5 kV and below. This activity addresses the risk associated with an arc-flash fire or sparking caused by animal contact with energized components that may project or propagate outside of HFTD/HFRA substations, potentially resulting in a wildfire.

Substation animal related arc flashes are mitigated through various mitigation materials and techniques that include pole-mounted climbing guards, critter covers/guards, tape-wraps, physical separation, shields, electric fences, or other deterrents on or near exposed energized components of substation equipment.

Impact of the Activity on Wildfire Risk

There is no impact on wildfire risk as PG&E has no recorded animal induced ignition events that have spread beyond the substation.

Impact of the Activity on Outage Program Risk

This activity has no impact on the frequency or location of PSPS events.

Updates to the Activity

PG&E will continue to execute small scale animal abatement as identified through the corrective notification process at substations and switchyards. Additionally, PG&E will continue to monitor animal abatement project triggers at substations to identify and prioritize additional projects as needed. This activity is now incorporated into our base reliability work. See Section 13.3, Table PG&E-13.3-1.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) are risk control activities. We implement these routine controls across our entire system. They are used alongside Substation Animal Abatement.

8.2.13 Status Updates on Additional Technologies Being Piloted

8.2.13.1 Transmission Avian Mitigation – Di-Electric Cover Pilot

Tracking ID: GH-13

Overview of the Activity

Avian contact with transmission lines can potentially pose an ignition risk as well as a reliability risk. PG&E is piloting ways to prevent birds from contacting the lines, including installation of equipment on towers to reduce the likelihood of birds perching on the towers. The commitment GH-13 will provide a feasibility study regarding these initiatives.

Impact of the Activity on Wildfire Risk

Avian protection measures may improve safety and ignition risks. PG&E is working to ensure adequate separation between energized components by studying technology that may work to insulate these grounded components. This is to strive to prevent incidental avian contact, which can lead to electrical flashover and wildfire ignition caused by the bird on the ground contacting vegetation.

Risk reduction/effectiveness of the activity is part of the pilot and will be assessed through a feasibility study (GH-13).

Impact of the Activity on Outage Program Risk

Avian protection can assist in reducing outage risk, by reducing likelihood of outages caused by bird contact. Risk reduction/effectiveness of the activity is part of the pilot and will be assessed through a feasibility study (GH-13).

The activity can reduce reliability risk as transmission lines are upstream of the distribution system and the interconnected customers. Hardening the transmission lines thus improves the reliability of the distribution system.

Updates to the Activity

This is a pilot; there is no update from the 2023-2025 WMP.

Compatible Initiatives

Activities such as on-going asset inspections (Section 8.3) and vegetation management (Section 9) are risk control activities. We implement these routine controls across our entire system. They are used alongside Traditional Overhead Hardening – Transmission Conductor. Additional programs used in combination with alongside Traditional Overhead Hardening – Transmission Conductor include: Transmission Pole/Tower Replacements and Reinforcements (Section 8.2.4); Routine Patrol – Transmission (Section 9.2.3); Protective Equipment and Device Settings (Section 8.7.1.1); and Equipment Maintenance (Section 8.4).

8.3 Asset Inspections

In this section, the electrical corporation must provide an overview of its procedures for inspecting its assets.[78]

The electrical corporation must first summarize details regarding its asset inspections in Table 8-2. The table must include the following:

- *Type of Inspection: i.e., distribution, transmission, or substation;*
- *Inspection Program Name: Identify various inspection programs within the electrical corporation;*
- *Frequency or Trigger: Identify the frequency or triggers, such as inputs from the risk model. Indicate differences in frequency or trigger by HTFD Tier, if applicable;*
- *Method of Inspection: Identify the methods used to perform the inspection (e.g., patrol, detailed, aerial, climbing, and Light Detection and Ranging (LiDAR));*
- *Governing Standards and Operating Procedures: Identify the initiative construction standards and the electrical corporation's procedures for addressing them, and other internal protocols for work described;*
- *Quarterly Targets: Provide the cumulative quarterly targets for each year of the WMP cycle;*[79]

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[78] *Pub. Util. Code § 8386(c)(10).*

[79] *Guidelines for WMP Update will provide additional instructions on future quarterly rolling target reporting.*

- *<u>Percent of HFRA and HFTD Covered Annually by Inspection Type</u>: Determine the percentage of either circuit mileage or number of assets covered annually by the inspection type within the HFRA and HFTD;*

- *<u>Find Rate</u>: Identify the find rate of Level 1, 2, and 3 conditions over the three calendar years prior to the Base WMP submission. The find rate must be expressed as the percentage of inspections resulting in findings and identify the inspection unit; and*

- *<u>Clarifying Information</u>: Provide electrical corporation-specific risk informed triggers used for asset inspections and electrical corporation-specific definitions of the different methods of inspection.*

The electrical corporation must then provide a narrative overview of each asset inspection activity (program) identified in the above table; Section 8.3.1. provides instructions for the overviews. The sections should be numbered Section 8.3.1 to Section 8.3.n (i.e., each asset inspection activity (program) is detailed in its own section). The electrical corporation must include inspection activities (programs) it is discontinuing or has discontinued since the last WMP submission; in these cases, the electrical corporation must explain why the activity (program) is being discontinued or has been discontinued. The electrical corporation must also include inspection activities (programs) being piloted; for pilot inspection activities (programs) the electrical corporations must include a discussion of how it measures the effectiveness of the pilot and how it determines next steps for the pilot (e.g., to expand, discontinue, or move to permanent activity (program)).

In this section, PG&E summarizes our processes and procedures for asset inspections, including details of the inspection process.

Inspection process details are included in Table 8-2, which lists PG&E's transmission, distribution, and substation asset inspection activities, methods of inspections, governing standards, and operating procedures for programs with quarterly targets. Inspection process details are included in Table PG&E-8.3-1 for programs without quarterly targets.

- <u>Reporting</u>: PG&E will use the targets in Table 8-2 below for quarterly compliance reporting including the QDR, QN, and the ARC. We note that throughout this 2026-2028 WMP, we discuss current plans for wildfire-related activities beyond the targets in Table 8-2. The timing and scope of these additional activities may change. We will not be reporting on these activities in our QDR, QN, or ARC because they are not defined targets, but are described in our 2026-2028 WMP to provide a complete picture of our wildfire mitigation activities;

- <u>External Factors</u>: All targets throughout this WMP are subject to External Factors. External Factors in this context are reasonable circumstances that may impact execution against targets including, but not limited to, physical conditions, environmental delays, landowner or customer refusals or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, wildfires, exceptions or exemptions to regulatory/statutory requirements, and other safety considerations;

- Utility Initiative Tracking IDs (Tracking IDs): We are including Tracking IDs in each section that has associated targets. Table 8-2 displays the Tracking IDs we are implementing to tie the targets to the narratives in the WMP. The Tracking IDs will also be used for reporting in the QDR; and

- *HFTD, HFRA, Buffer Zone Areas: Unless stated otherwise, all initiatives described in Table 8-2 involve work or audits on units or equipment located in, traversing, or energizing HFTD, HFRA, or Buffer Zone areas or involve units or equipment in HFTD, HFRA, or Buffer Zone areas.*

Please note that asset inspections are not typically planned for the first quarter of each year due to the uncertainty of weather conditions, like winter storms. However, if conditions permit, asset inspections will start as soon as feasible after the winter storm period.

TABLE-8-2:
ASSET INSPECTION FREQUENCY, METHOD, CRITERIA, AND QUARTERLY TARGETS

Type	Inspection Activity (Program)	Frequency or Trigger	Method of Inspection	Governing Standards and Operating Procedures[b]	Cumulative Quarterly Target 2026, Q1[c]	Cumulative Quarterly Target 2026, Q2	Cumulative Quarterly Target 2026, Q3	Cumulative Quarterly Target 2026, Q4	Cumulative Quarterly Target 2027, Q1	Cumulative Quarterly Target 2027, Q2	Cumulative Quarterly Target 2027, Q3	Cumulative Quarterly Target 2027, Q4	Cumulative Quarterly Target 2028, Q1	Cumulative Quarterly Target 2028, Q2	Cumulative Quarterly Target 2028, Q3	Cumulative Quarterly Target 2028, Q4	% of HFRA and HFTD Covered Annually by Inspection Type	Condition Find Rate Level 1	Condition Find Rate Level 2	Condition Find Rate Level 3
Transmission	Detailed (AI-04)	3 years or WTRM	Drone, aerial lift, or ground visual	GO 165, TD-8123P-100, TD-1001M	–	13,200	22,000	22,000	–	13,200	22,000	22,000	–	13,200	22,000	22,000	40%	0.2%	19.2%	14.7% (Asset)
Transmission	Infrared[a] (AI-06)	3 years or WTRM	Helicopter, drone, or a handheld sensor	GO 165, TD8123P100, TD-1001M, TD1001P14	–	500	1,500	2,500	–	500	1,500	2,500	–	500	1,500	2,500	40%	0.02%	0.15%	N/A (Circuit Mile)
Distribution	Aerial Scan[d] (AI-07A)	100% over 3-year cycle	Visual by aerial	GO 165, TD-2305M	–	30,000	50,000	50,000	–	12,000	20,000	20,000	–	12,000	20,000	20,000	5%	0.12%	0.66%	0.00%
Distribution	Detailed[e][f] (AI-07D)	100% over 3-year cycle	Visual by ground or aerial	TD-2305M-JA02, TD-2305P-03, TD-8123P-201	–	90,000	190,000	300,000	–	90,000	190,000	305,000	–	60,000	160,000	215,000	42%	0.15%	15.96%	0.95%

(a) Lines historically loaded below 40 percent may not be included for inspection due to low efficacy of method at low loading.

(b) Governing standards are available in Appendix E. Operating Procedures are available at: PG&E's Community Wildfire Safety Program.

(c) Even though inspections typically commence in Q1, our main focus is on updates to inspection criteria based on learnings from the previous year, inspector training, and responding to the numerous winter storms that are typical across the service area. To enable a flexible response to changing conditions, we have not set an inspection target for Q1. Our overall target for each year remains unimpacted.

(d) In response to Critical Issue RN-PGE-26-06, Aerial Scan (AI-07A) target was created. The target units together with Detailed Inspections – Distribution (AI-07D) aim to achieve a cumulative 57 percent EOR. See 2026-2028 WMP Revision Notice Response R0 for additional information.

(e) Historical find rates are from detailed ground inspections only.

(f) In response to Critical Issue RN-PGE-26-06, Detailed inspections and aerial inspections targets together account for 57% Eyes-on-Risk (EOR). PG&E aims to achieve a cumulative 57 percent EOR across aerial scan and detailed inspections. This EOR can be allocated in any way across the two inspections. See 2026-2028 WMP Revision Notice Response R0 for additional information.

TABLE PG&E-8.3-1:
ASSET INSPECTION FREQUENCY, METHOD, AND CRITERIA

Type	Inspection Activity (Program)	Frequency or Trigger	Method of Inspection	Governing Standards and Operating Procedures[f]	% of HFRA and HFTD Covered Annually by Inspection Type	Condition Find Rate Level 1	Condition Find Rate Level 2	Condition Find Rate Level 3
Transmission	Detailed Climbing	3 years	Climbing	GO 165, TD-8123P-100, TD-1001M	25-45% of 500 kV	0%	12.3%	2.4% (Asset)
Transmission	Intrusive Pole[a]	10 years by line not to exceed 20 years by structure	Ground/ intrusive inspection	GO 165, TD-2325S	5%-25% of wood poles	0.04%	11.3%	0.003% (Asset)
Transmission	Switch Function Tests[b]	8 years	Detailed Aerial with some function tests as triggered	GO 165, TD-1006P-02, TD-1001M	12-45%	0.6%	17%	0.5% (Asset)
Transmission	Patrol[c]	Every year not inspected by Detailed Inspection Program	Aerial or ground	GO 165, TD-8123P-100, TD-1001M	55-75%[d]	0.05%	0.18%	0.03% (Asset)
Transmission	Conductor Measurement	TBD – Pilot	LineVue robotic device	NA – Pilot	NA – Pilot	NA - Pilot	NA - Pilot	NA – Pilot
Transmission	Proactive Sampling/Testing	TBD – Pilot	Laboratory or field analysis	NA - Pilot	NA – Pilot	NA - Pilot	NA - Pilot	NA – Pilot
Distribution	Ground Patrol	WDRM V4	Visual	TD-8123S	~67%	0.035%	0.07%	0.003%
Distribution	IR Inspection	As needed to investigate emerging issues	Infrared	TD-2022P-01	N/A	(per circuit-mile inspected) 0	(per circuit-mile inspected) 0.53	(per circuit-mile inspected) 0
Distribution	Intrusive Pole Inspections	Approximately 10 or 20 year cycle[e]	Ground/hole-boring	TD-2325S & TD-2325P-01	N/A	0.084%	4.0%	0.58%
Distribution	LiDAR-Based Pole Loading Assessments	First time analysis – does not have a recurring frequency	Helicopter and vehicle	N/A	N/A	N/A	N/A	N/A
Distribution	Overhead Equipment Inspections	Annually	Ground visual	TD-2302P-05	100%	N/A	N/A	N/A
Distribution	Aerial Pilot	WDRM v3	Visual by aerial	Electric Distribution Preventive Maintenance (EDPM) Manual, TD8123M	100% over 3-year cycle	0.40%	35.9%	0.65%
Substation	Aerial (drone) Inspection	3-years or in-year based on risk	Aerial	TD-3322S	100% over 3-year cycle	See Table PG&E-8.3-15.1-1	See Table PG&E-8.3-15.1-1	See Table PG&E-8.3-15.1-1

(a) Method only applicable to wood poles. Inspection scope is regionally-optimized, leading to variable HFTD/HFRA coverage.
(b) Find Rate listed is for function tests. See Detailed Inspection for visual find rate.
(c) May change depending on yearly detailed inspection scope. Percent HFRA and HFTD covered by patrols in 100 percent with the inclusion of detailed inspections.
(d) Annual coverage of HFRA and HFTD is 100 percent, when combined with Transmission Detailed Inspections.
(e) PG&E plans to return to a 10-year PT&T cycle beginning in 2027.
(f) Governing standards are available in Appendix E. Operating Procedures are available at: PG&E's Community Wildfire Safety Program.

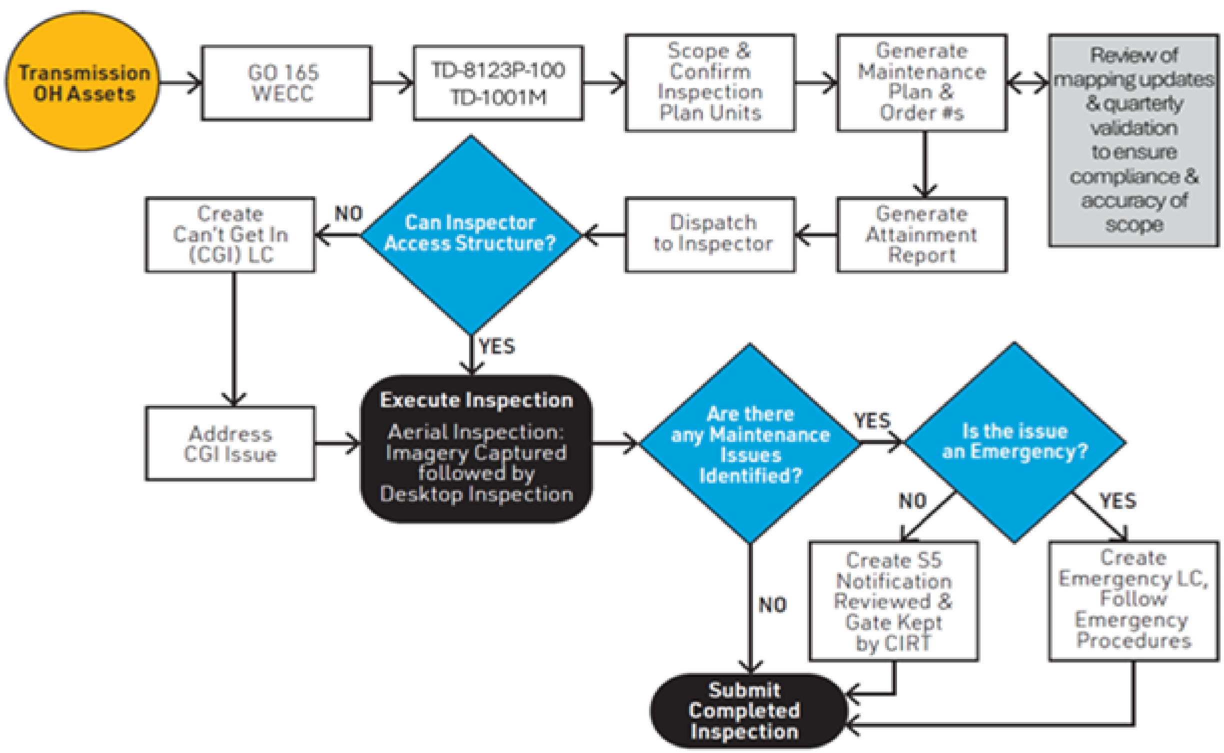
8.3.1 Transmission – Detailed Inspection Program

Tracking ID: AI-04

8.3.1.1 Overview

PG&E performs detailed visual inspections via aerial method (drone, helicopter, or aerial lift) paired with desktop image review or by an inspector on the ground. These routine inspections seek to visually identify asset conditions that could lead to an ignition. This initiative combines the Detailed Inspection Transmission Aerial and Ground initiatives (AI-04 and AI-02, respectively), mirroring Distribution initiative AI-07D and recognizing the shared visual assessment approach of these activities. PG&E considers the failure mode to determine the most effective inspection method for identifying the pre-failure conditions. The Transmission Detailed Inspection Activity is represented by Target AI-04 in Section 8.1. See Figure 8-1-1 below for the detailed inspection workflow.

FIGURE-8-1-1:
TRANSMISSION OVERHEAD ASSET INSPECTION PROCESS



8.3.1.2 Frequency or Trigger

Structures in the HFTD and HFRA undergo detailed inspection at least once every three years. The 3-year inspection cycle mirrors the maximum duration for addressing a Level 2 maintenance condition before further degradation is conservatively predicted to occur. In addition to this baseline cycle, structures may also be added to the inspection scope based on:

- Wildfire risk informed by the Transmission Composite Model (TCM) annualized probability of failure and Wildfire Consequence;
- Wildfire risk determined from a snapshot of the wildfire risk data from the year the scope is finalized; and
- Other factors such as inspection result trends, terrain/fire suppression considerations, employee field observations.

Target detailed inspection counts are represented by Target AI-04 in Section 8.1 and quarterly targets are provided in Table 8-3.

8.3.1.3 Accomplishments, Roadblocks, and Updates

The transmission inspection program measures success by achieving target AI-04.

Roadblocks include execution risks such as weather and access challenges.

From 2026-2028, PG&E will identify and inspect the highest wildfire risk and consequence assets identified from the WTRM while continuing to inspect a baseline of roughly one third of all assets in the HFTD/HFRA.

Ongoing improvements include:

- Inspector training based on feedback from QA/QC findings and field input;
- Deploying a desk and field review by the in-house inspection team, and field verification via internal audit to develop current and relevant in-year improvement opportunities; and
- Component testing on high severity conditions identified through inspection were completed to advance understanding of failure conditions. Results are used to confirm or update inspection checklists and job aids.

Through EPIC 3.41, "Drone Enablement," PG&E is demonstrating Beyond Visual Line of Sight drone-based asset inspection operations including the further automation of transmission inspections.

PG&E considers the comprehensive controls of monitoring as described in Section 10.3 in addition to inspections in the overall mitigation of asset risk.

8.3.2 Transmission – Detailed Climbing Inspection Program

Tracking ID: N/A

8.3.2.1 Overview

Climbing inspections are performed visually by an inspector climbing 500 kV steel structures. Measurements of the internal guy wires, which are unique to 500 kV structures, are taken for structures climbed, and adjustments are made if needed per the structure's engineering design. PG&E conducts these routine inspections to identify asset conditions that could lead to an ignition. Detailed Inspection Transmission—Climbing was removed as a target for 2026-2028 due to the focus of this activity on the structural integrity of 500 kV steel towers, which are not a significant contributor to ignitions.

See Figure 8-1-2 below for the climbing inspection workflow.

8.3.2.2 Frequency or Trigger

PG&E conducts a climbing inspection on structures in the HFTD and HFRA that are 500 kV at least once every three years. The 3-year inspection cycle mirrors the maximum duration for addressing a Level 2 maintenance condition before further degradation is expected to occur. In addition to this baseline cycle, structures may also be added to the annual inspection scope based on factors such as inspection result trends, engineering recommendations, employee field observations, etc.

8.3.2.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success by achieving internal PG&E targets and compliance.

Roadblocks include execution risks such as weather and access challenges, including ability to get to the location and access private property.

Ongoing improvements include:

- Inspector training based on feedback from QA/QC findings and field input; and
- Deploying a desk and field review by the in-house inspection team, and field verification via internal audit to develop current and relevant in-year improvement opportunities;

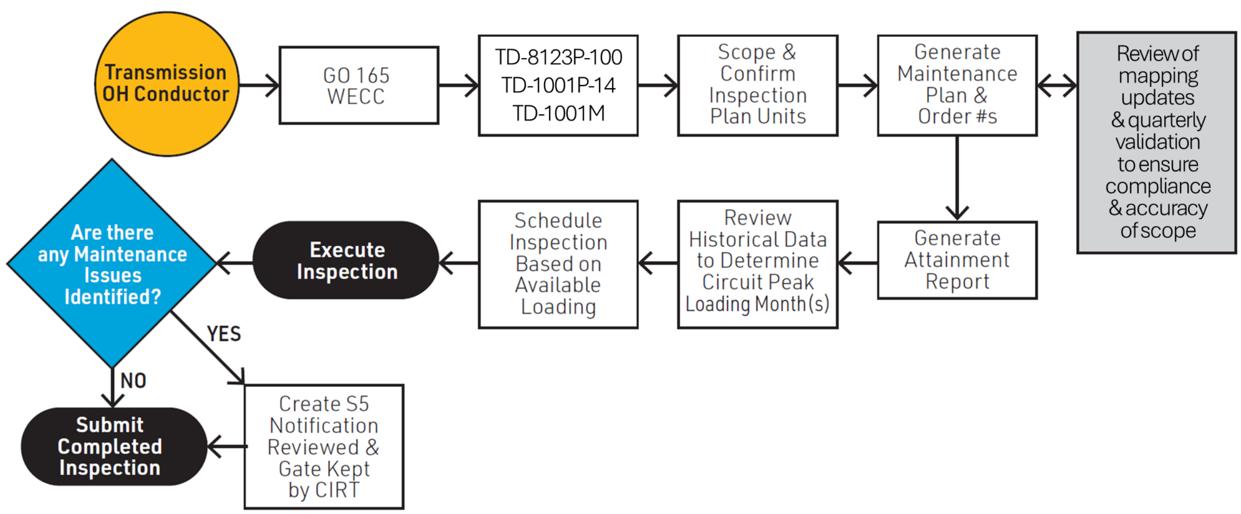
8.3.3 Transmission – Infrared Inspection Program

Tracking ID: AI-06

8.3.3.1 Overview

Infrared (IR) routine inspections are performed via helicopter, drone, or a handheld sensor. When captured via helicopter, corona inspections are performed simultaneously to proactively identify asset conditions that could result in an ignition. Corona inspections assess non-visible conditions by detecting corona concentration (free electrons that fragment stable oxygen molecules (O_2) combining with others to create ozone (O_3) gases). IR inspection effectiveness depends on adequate circuit loading and weather conditions. The Infrared Inspection activity is represented by Target AI-06 in Section 8.1. See Figure 8-1-2 below for the infrared inspection workflow.

FIGURE-8-1-2:
TRANSMISSION OVERHEAD CONDUCTOR INFRARED INSPECTION PROCESS



8.3.3.2 Frequency or Trigger

Transmission IR inspections are completed on energized circuits in the HFTD and HFRA at least once every three years. The 3-year inspection cycle mirrors the maximum duration for addressing a Level 2 maintenance condition before further degradation is expected to occur. In addition to this baseline cycle, circuits may also be added to the annual inspection scope based on:

- Wildfire risk informed by the wildfire transmission risk model (WTRM v2) annualized probability of failure and Wildfire Consequence; and
- Other factors such as inspection result trends, terrain/fire suppression considerations, employee, field observations.

Lines historically loaded below 40 percent (as determined by the 90th percentile amperage reading on the lowest rated line segment during daylight hours in a given year on a circuit) may not be included for inspection due to low efficacy of method at low loading. At low loading, component defects have a lower increase of temperature that this method may not detect.

Target infrared/corona inspection counts are represented by Target AI-06 in Section 8.1.

8.3.3.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success by achieving Target AI-06.

Roadblocks include execution risks such as achieving a higher electrical load on the transmission line during the inspection.

IR is most effective when transmission lines are adequately loaded, carrying currents in proportion to their electrical specifications. This presents a challenge when scheduling IR inspections, which need to balance historical loading patterns when lines are most in use and other conditions such as weather. Improvements were made in 2022 and later to time inspections with historic high loading periods to improve inspection efficacy.

The IR inspection team has been trained in corona inspection to move the corona pilot to a program that could be employed simultaneously with helicopter IR capture where the corona is built into the instrument setup.

8.3.4 Transmission – Intrusive Pole Inspection Program

Tracking ID: N/A

8.3.4.1 Overview

Intrusive pole inspections, also referred to as Pole Test and Treat (PT&T), probe the interior of the pole for early detection of deterioration and may include additional preservative treatment for poles above 25 years. Intrusive pole inspections may include visual inspection, sound inspection (hammer test), and below-grade external inspection (excavation). These routine inspections seek to identify asset conditions (primarily wood pole decay) that could lead to a pole failure.

8.3.4.2 Frequency or Trigger

Intrusive pole inspections are scheduled as part of a 10-year cycle by circuit with individual poles and newly-constructed circuits not to exceed 20 years, in accordance with PG&E procedures. This inspection cadence is recommended for the environmental conditions such as in PG&E's service territory.[80,81]

8.3.4.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success by completion of GO 165 inspections.

Roadblocks include execution risks such as weather and access challenges.

The intrusive test program inspection form platform moved to an internal digital tool to better interface with SAP in 2024. PG&E is exploring using a new technology to intrusively test poles through a resistograph drill technology in 2024 and beyond. This technology would remove the need for pole excavation and could provide more precise measurements on the extent of pole decay. There may be limitations to this technology's adoption based on certain factors such as pole size, type, and location, and the traditional intrusive method may be used instead.

8.3.5 Transmission – Switch Function Testing Program

Tracking ID: N/A

8.3.5.1 Overview

Switch function tests are performed either by a detailed visual inspection and/or a functional exercise to ensure the switch is operating properly depending on switch type and wildfire risk. Lubrication and battery testing may also be included depending on the type of switch. These routine inspections seek to identify asset conditions that could lead to an ignition.

8.3.5.2 Frequency or Trigger

Transmission line switch function testing is conducted on an 8-year cycle. For higher risk switches as determined by switch type and wildfire risk, both a visual inspection, as well as a function exercise, will be performed. For lower risk switches, only a visual inspection will be performed.

The current cycle began in 2021 and will end 2028. High fire consequence switches in the current cycle (including HFTD and HFRA) were prioritized for testing. PG&E is on

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80 United States Department of Agriculture Rural Utilities Service Bulletin 1730B-121, "Wood Pole Inspection and Maintenance." (2013), available at: <https://www.rd.usda.gov/files/UEP_Bulletin_1730B-121.pdf>.

81 American Wood Protection Association (AWPA) Standard M13-07, "Guidelines for a Pole Maintenance Program" (2008).

track to complete testing on this subset of switches by the end of 2025; therefore, there will be no remaining switches to test in the HFTD/HFRA during the current 8-year cycle. After 2025, the remaining 2021-2028 scope will be switches that are not in HFTD or HFRA. Our 8-year cycle length was determined through benchmarking against other utilities (6 to 10 years) and feedback from our internal execution teams.

T-line switches have additional controls and mitigations:

- HFTD/HFRA switches are inspected aerially once every 3 years via routine detailed drone-based inspections (see Section 8.3.1.1, Tracking ID AI-04) and Infrared inspections (see Section 8.3.3.1, Tracking ID AI-06).
- There are onsite field controls in place for switch operations:
  - At FPI ratings of R2 and above, switches are operated manual only by a Qualified Electrical Worker (QEW); and
  - At FPI ratings of R3 and above, a Safety & Infrastructure Protection Team (SIPT) is present and prepared to respond to an ignition should one occur.

See Revision Notice Response to Critical Issue RN-PGE-26-07 for additional information.

8.3.5.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success by achieving internal PG&E targets and compliance.

Roadblocks include execution risks such as the ability to obtain electrical clearances to perform the function tests.

PG&E bundles switch inspection and/or function tests with other planned line work clearances because they must be coordinated due to reliability considerations. However, function testing is challenging because clearances sometimes cannot be extended and resources may not be available to add on this inspection/testing work to existing clearances. Execution of this activity will be a hybrid of specifically planned inspection for lines without existing clearances and will be bundled with other work.

8.3.6 Transmission – Patrol Inspection Program

Tracking ID: N/A

8.3.6.1 Overview

Patrols are brief, visual inspections of applicable utility facilities (equipment and structures) that are designed to identify obvious structural problems and hazards. Patrols are visual routine reviews of the asset condition to detect imminent or existing safety and reliability hazards. Transmission overhead patrols may be executed on foot or by vehicle based on the terrain. Patrols are a brief visual inspection of an asset rather than a full visual examination as when a detailed inspection is performed.

8.3.6.2 Frequency or Trigger

Patrols of transmission electric lines and associated equipment are completed annually for assets not scheduled for a detailed inspection within the calendar year.

8.3.6.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success based on completion of patrols for all structures in HFTD/HFRA that do not receive a detailed inspection in a given year.

Roadblocks include execution risks such as weather.

Patrols are currently logged manually to note completion, which prevents easy tracking of findings. Discovery work is being performed to inform potential digitization of patrol forms in 2027.

8.3.7 Transmission – Pilot Inspection Programs

Tracking ID: N/A

8.3.7.1 Overview

There are some conditions that may not be easily detected via visual inspections, such as conductor degradation or component remaining strength. Since failure to detect these types of conditions could lead to asset failure, PG&E has additional inspection efforts in the pilot phase.

- Conductor Measurement/Inspections: This activity assesses the condition of steel core conductors by measuring the remaining cross-sectional area of steel core wires and detecting local flaws such as deep pits or broken strands (by measuring magnetic flux leakage), which may be difficult to identify visually.

- Proactive Sampling and Testing: This activity involves taking equipment samples and performing various tests and analyses to understand the overall conditions of asset(s) and the factors that promote their failure for programmatic repair/replacement decisions. Testing may involve visual examination (i.e., internal/external corrosion and electrical damage), electrical testing (resistance measurement), and mechanical testing (e.g., measure breaking strength). Sampling typically involves coordinated collection of specific type(s) or size(s) of assets from strategic locations on a transmission circuit for evaluation.

8.3.7.2 Frequency or Trigger

As these programs are in pilot phase, PG&E has not yet developed inspection frequencies. Workplans will be prioritized using the WTRM v2 and considerations of asset health, environmental conditions, and past failures.

8.3.7.3 Accomplishments, Roadblocks, and Updates

The measure of success for this initiative is the execution of the pilots and evaluation on how and if the methodology should be integrated into broader transmission inspection programs.

Roadblocks include potential technology changes that may need to occur to perform the pilot and capture relevant data.

Conductor Measurement/Inspections: There have been low find rates with this pilot since 2022 and further piloting is being performed to identify the target population that would benefit from this inspection method.

Proactive Sampling and Testing: This has been a pilot since 2022 due to improvements that are being made to coordinate targeted sampling with the field with existing clearance schedules. We are also still endeavoring to identify a targeted population that would most benefit from this testing.

8.3.8 Distribution – Detailed Inspection Program

Tracking ID: AI-07A, AI-07D

8.3.8.1 Overview

Distribution Inspections Overview

PG&E's distribution inspections support the overall wildfire objective by identifying unknown hazards or risky conditions to be addressed. To accomplish this, a holistic approach to inspections planning was developed to increase the eyes-on-risk at locations with the highest wildfire risk or consequence of a wildfire. As a baseline, every distribution structure in HFTD/HFRA areas will receive a detailed inspection every three years. PG&E has three types of visual distribution inspections: Detailed Inspections, Aerial Scan Inspections, and Patrols. These visual inspection programs are planned together, with the Aerial Scan Inspections supplementing the detailed inspections, increasing the eyes-on-risk for the highest risk and consequence locations. Detailed descriptions of how the inspection methods are planned are described in the frequency or trigger sections.

Detailed Inspections Program Overview

The Detailed Inspections Program utilizes the inspections process workflow outlined in Figure 8-1-3 and Figure 8-1-4 to carefully examine overhead assets in compliance with the GO 165 requirement. PG&E conducts this inspection on a 3-year cycle in HFTD and HFRA locations, which exceeds the GO 165 mandate of 5 years.

Detailed inspections are visual inspections of PG&E's distribution structures. During these inspections, abnormal compelling conditions are identified. Abnormal compelling conditions are visible electric distribution pole, equipment, component, conductors, vegetation, or third-party conditions that may cause a safety, reliability, or fire ignition risk. The Overhead Job Aid (TD-2305M-JA02)[82] is used to assess and prioritize any abnormal compelling conditions found. During a detailed inspection, the inspector also uses an inspections checklist, reviewing the structure for these abnormal compelling conditions. In the past, PG&E has exclusively performed detailed inspections using ground crews, but as PG&E continues to mature its aerial distribution inspection processes and tools, this inspection may also utilize aerial methods.

Aerial Scan Inspection

The Aerial Scan Inspection is a new inspection to get additional eyes-on-risk for the riskiest areas. Aerial scans will leverage PG&E's experience with aerial inspections in 2024 and 2025. The scan inspection will consist of a review of a streamlined set of photos. The photos have been tailored to enable identification of the conditions on the structure and equipment that pose the highest wildfire risk, including the mid-span conductor. This additional focus on mid-span conditions enables a more comprehensive view of assets to supplement the detailed inspections.

Aerial scans will be completed by drone along a circuit or circuit segment. Aerial scans will capture emergency as well as urgent non-emergency conditions, corresponding to PG&E's A, X, and B tags. Conditions identified will be prioritized according to PG&E's Overhead Job Aid.

See Revision Notice Response to Critical Issue RN-PGE-26-06 for additional information.

Real Time Sensors

PG&E is also piloting real time sensors. As this technology matures over this WMP period, PG&E may substitute Aerial Scan Inspections with the data obtained from real-time sensors.

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82 The supporting document is available at: PG&E's Community Wildfire Safety Program.

FIGURE-8-1-3:
GROUND INSPECTIONS PROCESS WORKFLOW

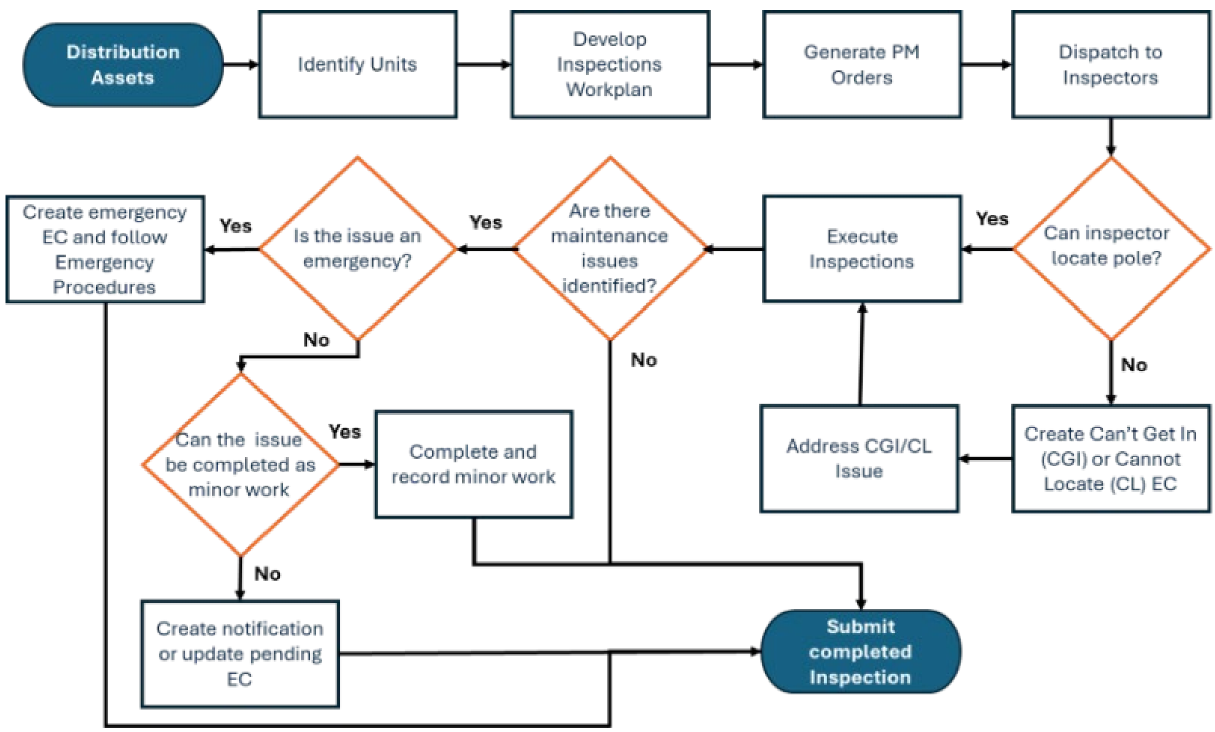
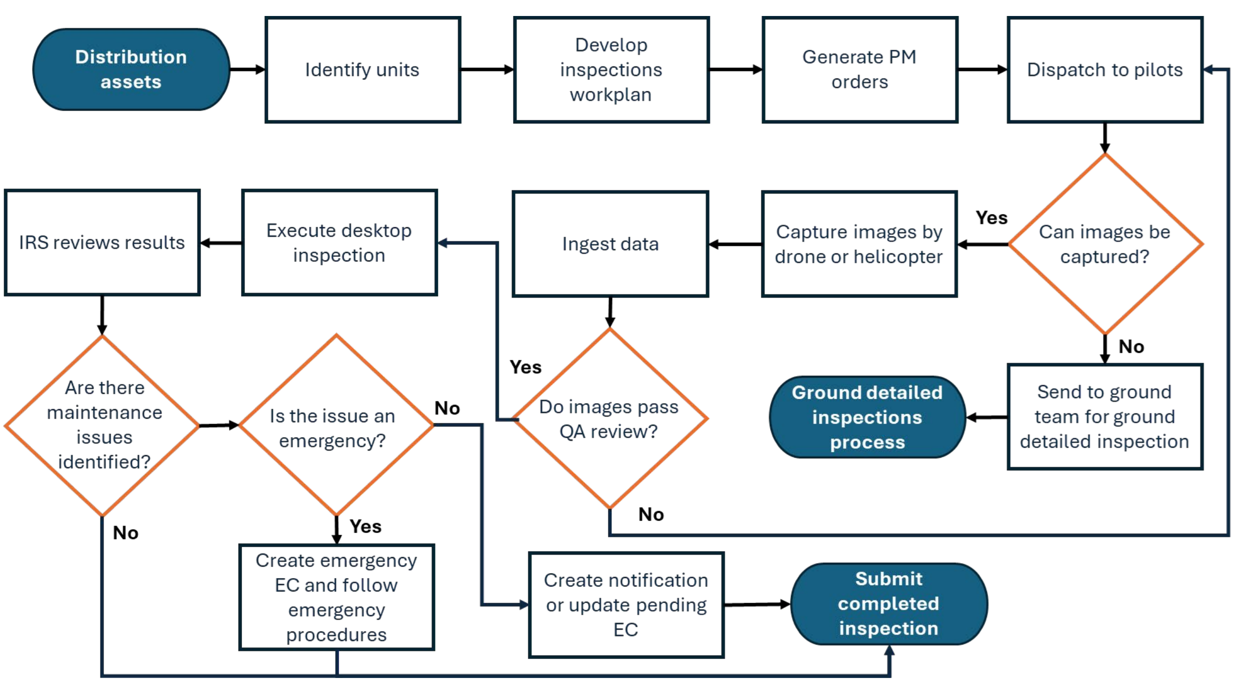


FIGURE-8-1-4:
AERIAL INSPECTIONS PROCESS WORKFLOW



Assets in the HFTD and HFRA will receive a detailed inspection on a 3-year cycle. The riskiest locations as determined by WDRM v4 and those locations with the highest consequence will be inspected more frequently utilizing the aerial scans. The aerial scans offer additional eyes-on-risk for identifying conditions that require short-term remediation.

PG&E has committed in AI-07A to complete aerial scan inspections on distribution poles and in AI-07D to complete detailed inspections on distribution poles, which will be identified in PG&E's asset registry at the time of work plan development. See Table 8-1 and Table 8-2 for more information. Please note that this projected target may require modification based on changes in the asset registry.

8.3.8.2 Frequency or Trigger

PG&E will conduct detailed inspections on all distribution overhead assets in HFTD and HFRA with the criteria and guidance set forth in PG&E's Overhead Job Aid (TD-2305M-JA02).[83] PG&E will inspect all structures in HFTD and HFRA areas on a 3-year cycle, which goes beyond the 5-year requirement in GO 165.

PG&E will supplement the detailed inspections with aerial scan inspections in between the 3-year detailed inspection cycles. To identify the high-risk locations where Aerial Scan Inspections will be conducted, PG&E utilizes a 5x5 matrix of wildfire consequence and wildfire risk (WDRM v4). A consequence dimension is used in addition to risk to prioritize inspections in locations where any event could be catastrophic, but the probability of failure might be unknown. Figure PG&E-8.3.8.2-1 depicts the risk and consequence categories: Extreme, Severe, High, Medium, and Low, showing how many structures fall into each category. Figure PG&E-8.3.8.2-2 depicts inspection cycles by risk group.

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83 The supporting document is available at: PG&E's Community Wildfire Safety Program.

FIGURE PG&E-8.3.8.2-1:
INSPECTION SELECTION PROCESS

Inspection Selection Process

Consequence					
Extreme	0	0	20	920	2,146
Severe	0	0	3,746	2,488	437
High	4,045	28,216	48,372	1,407	124
Medium	219,987	56,816	9,403	12	0
Low	277,815	2,179	1	0	0
	Low	**Medium**	**High**	**Severe**	**Extreme**
	Wildfire Risk				

Annual Inspection   *Bi-Annual Inspection*   *Tri-Annual Inspection*

FIGURE PG&E-8.3.8.2-2:
INSPECTION CYCLES BY RISK GROUP

<table>
<tr><th rowspan="2">Categorization</th><th colspan="6">WDRM v4 Wildfire Risk / Consequence Grouping</th></tr>
<tr><th>Extreme</th><th>Severe</th><th>High</th><th>Medium</th><th>Low</th><th>Total</th></tr>
<tr><td>HFTD/HFRA Structures[1]</td><td>3,631</td><td>7,620</td><td>89,652</td><td>277,790</td><td>276,628</td><td>655,323</td></tr>
<tr><td>Eyes on Risk</td><td colspan="2">Annually</td><td>2 out of 3 Years</td><td colspan="3">3-Year Cycle</td></tr>
<tr><td>Detailed Inspections</td><td colspan="6">3-Year Cycle</td></tr>
<tr><td>Aerial Scan Inspections</td><td colspan="2">Years when detailed inspections do not occur[2]</td><td>3-Year Cycle[3]</td><td colspan="3"></td></tr>
<tr><td>Real Time Sensors</td><td colspan="3">Target Locations</td><td colspan="3"></td></tr>
</table>

Notes: (1) All HFTD/HFRA structure counts in this table are based on an asset registry date of February 5, 2025. The actual structure counts for work plans for 2026-2028 will be different and based on asset registry dates closer to when work plans are developed. (2) Creates a schedule with eyes-on-risk annually (3) Creates a schedule with eyes-on-risk at least biannually

Frequency/Trigger for Aerial Scans

Aerial Scan Inspection cycles were designed to ensure that locations with the highest wildfire risk and probability receive additional eyes-on-risk in between three-year cycles of detailed inspections. Extreme and Severe areas will have eyes-on-risk annually, so will receive a scan in all years they do not receive a detailed inspection. High category areas will have eyes-on-risk at least every once every two years, so high structures receive either a scan or detailed inspection every other year. Those in the Medium and Low categories will only receive a detailed inspection on a three-year cycle. However, additional structures of any risk or consequence category may be added to achieve eyes on risk targets. .

The schedule for detailed inspections and scanned inspections are developed based on operational field knowledge, coordination with other programs (such as patrols), and constraints, including restricted physical access periods.

8.3.8.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success based on achieving the AI-07A and AI-07D targets.

As with other inspection programs, PG&E’s roadblocks will continue to be weather and access.

PG&E has significantly evolved its detailed distribution inspections. Key accomplishments and areas for future improvement include the following:

1) Expansion of Aerial Inspections: Based on successful pilots in previous years, PG&E scaled its aerial inspections in 2024, inspecting over 220,000 poles. The Aerial program leverages drone to capture high resolution images that allow inspectors to better assess the top of pole conditions such as cross-arm deterioration, loose hardware etc., PG&E provides photos and find rates from its aerial inspection in Figure PG&E-8.3.8.3-1, Figure PG&E-8.3.8.3-2, and Figure PG&E-8.3.8.3-3.

   In 2025, PG&E plans to evaluate whether aerial inspections could be enhanced to include tree connections, anchors, and other ground-level issues. This study would inform our thinking on how the GO 165 detailed inspection might leverage aerial technology in the future.

2) Simplified Inspection Checklist: Based on a 2023 equipment failure study and feedback from field personnel, the inspection checklist was simplified from over 100+ questions to focus on the assets that drive 97 percent of asset failures: pole, crossarm/insulator/cutout, transformer, conductor. Additionally, the mobile inspection platform was updated to allow inspectors to easily access the inspection job aid from their hand-held devices.

3) Updated Inspection Job Aid: Based on feedback from inspectors and inspection review teams that there was significant subjectivity in how asset conditions were assessed, PG&E updated its Overhead Job Aid to provide more objective inspection criteria and picture examples. Updated criteria were based on engineering analyses and/or lab testing on specific failure modes.

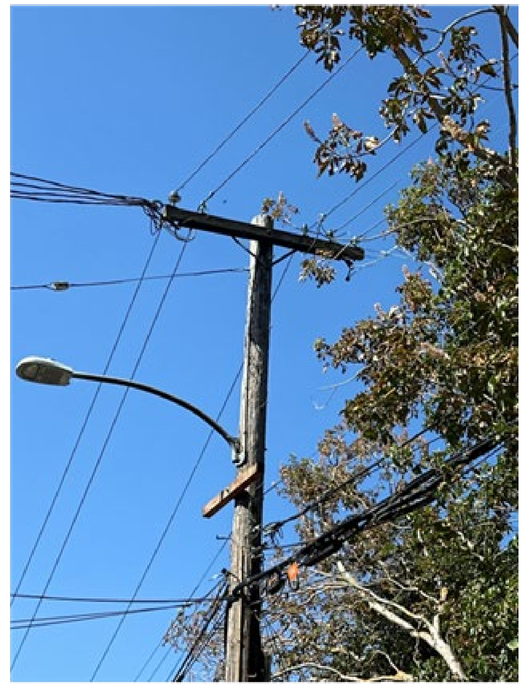
4) Piloted Comprehensive Pole Inspection (CPI): In 2023 and 2024, PG&E piloted CPI to re-evaluate EC open notifications using enhanced inspection methods and updated criteria. The CPI program consists of two main components: (1) intrusive pole inspection to validate tags created for pole rot conditions on the lower half of the pole, and (2) aerial inspection to validate the pole top conditions. Inspectors leveraged the updated inspections job aid, which included more detailed and objective guidance on pole conditions.

The following images show examples of ground versus aerial images of conditions that are difficult to assess from ground visual inspections. Figure PG&E-8.3.8.3-1 depicts aerial inspection find rate by notification priority.

FIGURE PG&E-8.3.8.3-1:
IMAGES OF AERIAL CONDITIONS IDENTIFIED (1 of 3)

Note: Figure PG&E-8.3.8.3-1 shows damaged primary conductor. The picture on the left was captured by Aerial Inspections, while the picture on the right was captured by Ground Inspections.

FIGURE PG&E-8.3.8.3-2:
IMAGES OF AERIAL CONDITIONS IDENTIFIED (2 of 3)



Note: Figure PG&E-8.3.8.3-2: Loose tie-wire with secondary conductor resting on the crossarm. The picture on the left was captured by Aerial Inspections, while the picture on the right was captured by Ground Inspections.

FIGURE PG&E-8.3.8.3-3:
IMAGES OF AERIAL CONDITIONS IDENTIFIED (3 of 3)

Note: Figure PG&E-8.3.8.3-3 shows a broken, damaged, or rotten pole at the top, captured by Aerial Inspections.

TABLE PG&E-8.3.8.3-1:
2024 HFTD-HFRA AERIAL INSPECTION FIND RATE BY NOTIFICATION PRIORITY

Electric Corrective Notification Priority	HFTD-HFRA, Aerial Find Rate (Percentage of HFTD-HFRA Aerial Inspections on Structures Without an Open Notification)	HFTD-HFRA, Ground Find Rate (Percentage of HFTD-HFRA Ground Inspections on Structures Without an Open Notification)
A	0.15%	0.23%
X	0.27%	0.29%
B	3.33%	2.6%
E	32.3%	13.9%
F	0.65%	4.3%

Note 1: Every year PG&E's inspection workplan includes locations with an open notification and locations without an open notification. Therefore, the rates of EC Notification creation shown in Table 8.3.8.3-1 cannot be applied to total outstanding inspection counts to predict future notifications. They must be applied to inspections on structures without an open EC notification. Roughly 6,000 structures without an open notification were inspected in HFTD/HFRA by ground and 140,000 by aerial in 2024.

Note 2: As highlighted in the table above, Aerial inspections have a higher find rate of non-emergency notifications compared to ground. This is expected because PG&E started aerial inspections at scale in 2024, and aerial inspections provide a unique vantage point for the top of pole conditions. We anticipate these find rates to decline when the same structures are re-inspected with aerial in the next cycle.

5) Pilot Sensors to Augment and Evolve the Inspection Program: PG&E's longer-term goal is to leverage sensing technology (e.g., pole sensors) to get real time eyes-on-risk at targeted high-risk locations. Real-time sensing devices provide situational intelligence on the structure by signaling that there are damages that can lead to ignition and/or outages. Once the remote sensing technology and the operational integration matures, PG&E will be leveraging these devices to get constant eyes-on-risk, reducing the need for extra visits to structures in between detailed inspections.

8.3.9 Distribution – Patrol Inspections Program

Tracking ID: N/A

8.3.9.1 Overview

Patrol inspections are simple, visual examinations of applicable overhead and underground facilities to identify obvious structural problems and hazards in alignment with GO 165. Distribution overhead patrols may be executed on foot, by vehicle, or by aerial means and are intended to identify any significant hazards. They are conducted on HFTD and HFRA assets that do not receive a detailed inspection.

8.3.9.2 Frequency or Trigger

PG&E will patrol all known assets in the HFTD that did not receive a detailed inspection. PG&E's patrol program is a routine activity conducted in alignment with GO 165. No targets are set for this program.

8.3.9.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success based on completion of patrols for all structures in HFTD/HFRA that do not receive a detailed inspection.

As with other distribution inspection programs, PG&E's roadblocks continue to be weather and access.

No changes are expected in the patrols program from the prior WMP cycle.

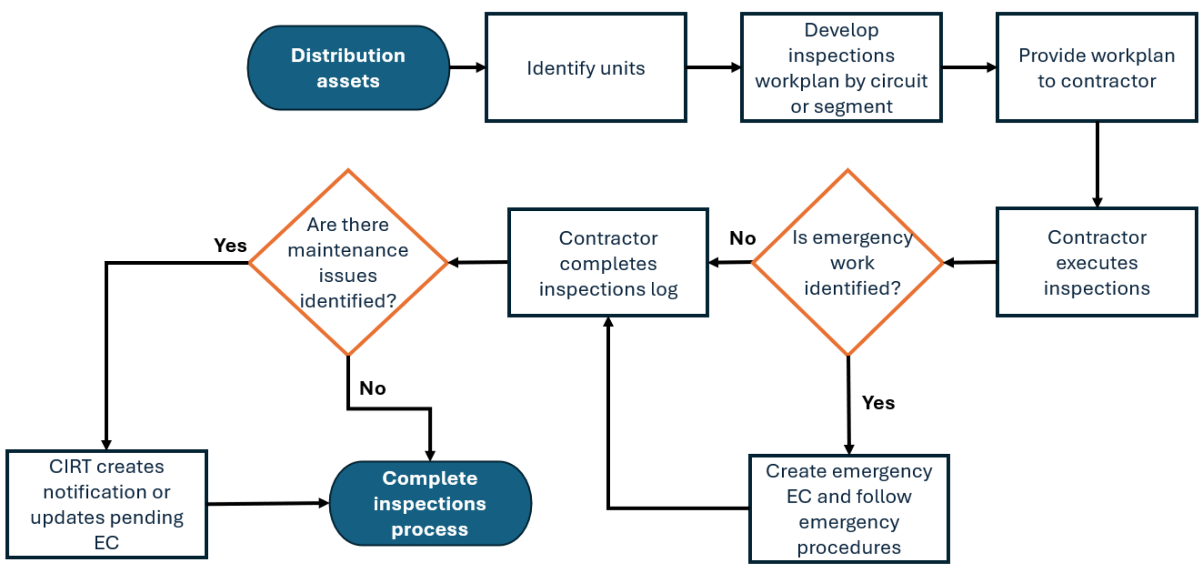
8.3.10 Distribution – Infrared Inspections Program

Tracking ID: N/A

8.3.10.1 Overview

Inspecting overhead electric distribution lines and equipment using Infrared (IR) technology and cameras can identify hot spots or conditions that indicate potential equipment failure. Although most failure modes can be detected via visual inspections, there are some that cannot (e.g., components experiencing excessive heat condition). IR inspections help identify potentially damaged and/or faulty components that are not detectable by visual inspection. See Figure 8-1-5 below for the infrared inspection workflow.

FIGURE-8-1-5:
INFRARED INSPECTION WORKFLOW



8.3.10.2 Frequency or Trigger

Between 2020-2022, PG&E completed inspections of all circuits in the HFTD/HFRA. Starting in 2023, PG&E focused on re-evaluating the role of IR within PG&E's broader overhead inspections programs, as well the standards and processes supporting the program. Based on the find rates and effectiveness of this technology compared to other inspection methods, PG&E focused its IR inspections in specific areas with known concerns that IR would be able to detect, such as conductor damage from outside conditions. These targeted inspections were focused in non-HFTD, where IR has not been used on overhead assets programmatically since 2019. PG&E's intention was to detect suspected failure modes on certain structures or components instead of performing inspections on a mileage basis. When deployed to these targeted areas, PG&E found significantly higher find rates.

In the 2026-2028 WMP cycle, PG&E will continue to target IR to areas of emerging concern as needed. For example, PG&E may deploy IR inspections to complete an assessment of at-risk structures/equipment during high loading or abnormal circuit configuration conditions. PG&E has not set targets for this program given the as-needed nature of the program.

8.3.10.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success based on completion of circuits or circuit segments identified for inspection that year.

As with other distribution inspection programs, PG&E's roadblocks continue to be weather and access.

From 2023 through 2024, key accomplishments include the following:

1) Completed Approximately 5,600 Distribution Circuit Miles in HFTD/HFRA: Connector hot spots continued to be the most common finding from IR inspections.

2) Piloted Drone-Mounted IR Cameras: In 2024, PG&E considered the effectiveness of the IR technology, specifically examining the method of inspection. PG&E has been using an IR camera mounted on a ground truck. However, in 2024, PG&E duplicated some locations using a drone with an IR camera for the infrared inspections. The drone IR camera was able to replicate findings from the ground IR camera. In coming years, PG&E will continue to explore the alternative method of drone IR to determine if it is cost effective.

3) Updated IR Criteria: In light of the activities above and benchmarking with other utilities, PG&E updated its IR standard, TD 2022P 01 rev. 3, to include more asset types for recording hot spot findings and updated the priority tables.

8.3.11 Distribution – Intrusive Pole Inspections Program

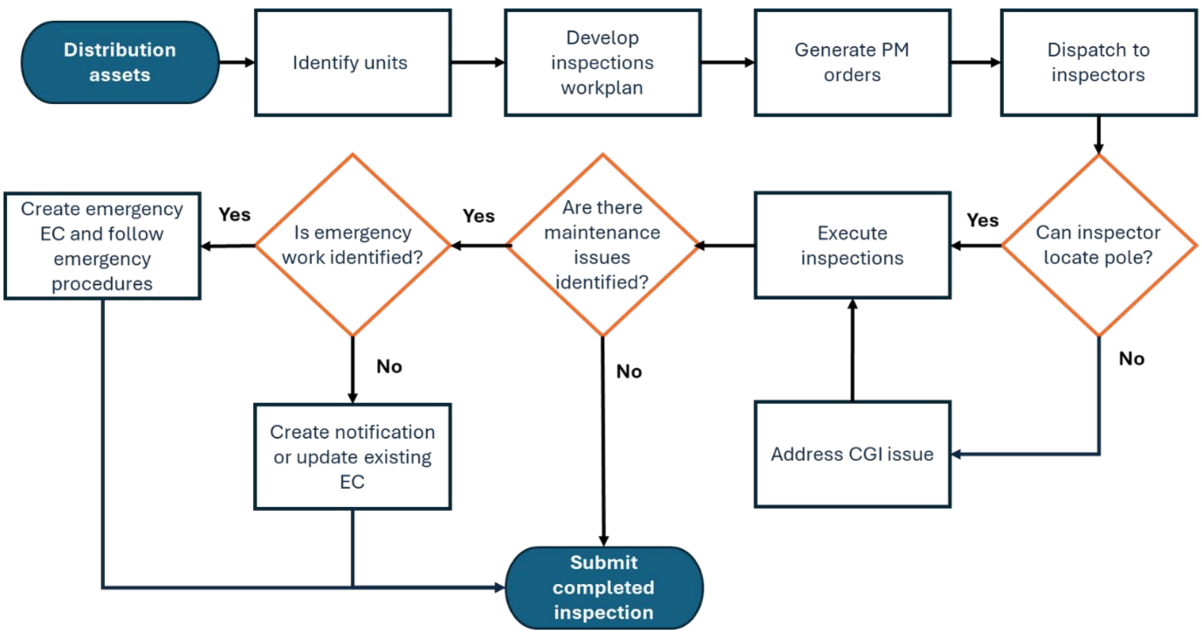
Tracking ID: N/A

8.3.11.1 Overview

Intrusive pole inspections—also called PT&T—evaluate in-service wood poles for early signs of deterioration. PT&T is an activity to prevent premature failure of wood pole structures due to internal rot or shell degradation. The inspections identify wood poles that are nearing the end of their service life and require replacement or reinforcement to avoid a potential failure, which could result in a reliability or safety event, including an ignition. PT&T prolongs the service life of wood poles through reapplication of preservative and/or restoration of structural strength through reinforcement. PG&E's PT&T program has existed since 1994 and is fully implemented across transmission and distribution wood pole structures.

When intrusively inspecting wood poles, PG&E examines the internal and external condition of the pole at and below groundline, directly measuring shell thickness and examining below ground degradation. These inspections include visual assessment, sound inspection (hammer test), and below groundline external inspection (excavation). In addition, the inspections include boring the pole or pulling past bore samples to assess the internal health of the wood. Upon completion of the test, fumigant is poured into the bored holes to prevent fungus or other growth. In addition, if required, based on external assessment, a paste and paper may be applied to the pole below groundline. These treatments prolong the service life of the wood poles, protecting against environmental hazards, such as fungus. The intrusive inspection helps to indicate the level of decay and degradation of the poles. This assessment helps to quantify the overall system risk of potential pole failures and informs mitigation plans. See Figure 8-1-6 below for the intrusive pole inspection workflow.

FIGURE-8-1-6:
PT&T INSPECTION WORKFLOW



8.3.11.2 Frequency or Trigger

PT&T has been identified as a valuable source of information for identifying pole health to identify the poles that should be removed from service. PT&T has historically been conducted on wood poles systemwide approximately every ten years, more frequently than the GO 165 requirement of 20 years. PG&E's focus in the 2023-2025 period was on piloting and deploying other wildfire inspections methods, including aerial inspections and comprehensive pole inspections. PG&E plans to return to a 10-year PT&T cycle beginning in 2027. The PT&T program is service-territory wide, rather than limited to the HFTD/HFRA. Additionally, enhanced detailed inspections or other field activities may trigger the need for off-cycle intrusive testing. PG&E's intrusive pole inspections program is a routine activity conducted in alignment with GO 165, so no targets are set for this program.

8.3.11.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success based on completion of inspections within the GO 165 timeline.

As with other distribution inspection programs, PG&E's roadblocks continue to be weather and access.

PG&E's key accomplishments and plans for PT&T are described below:

1) Updated PT&T Process: Based on benchmarking and learnings from the field, PG&E revised utility procedure (TD-2325P-01).[84] The revised procedure has improved cellon pole criteria and calls for enhanced testing methods to drill at least one new bore hole when intrusively inspecting wood; and

2) PT&T performs a desktop verification for routine PT&T inspections.

3) In 2024, PG&E conducted 5,832 routine intrusive inspections in HFTD/HFRA; of this amount, 4.4 percent were identified for replacement.

In addition, PG&E is evaluating a less intrusive approach to PT&T utilizing a resistograph, a piece of equipment that measures resistance when drilling a small hole through the wood pole and calculates the wood health.

Further, PG&E is evaluating transitioning the PT&T inspection rejection criteria from wood strength to safety factor. This approach includes performing a pole loading calculation, which considers the decay of the pole, as well as the loads from conductors and equipment, providing a comprehensive view of the health of the pole.

PG&E is intending to pilot these methodologies in the 2026 to 2028 period.

8.3.12 Distribution – LiDAR-Based Pole Loading Assessments Program

Tracking ID: N/A

8.3.12.1 Overview

Determining whether an electric pole is overloaded can be an important element in preventing pole failure, thereby reducing potential ignition risk. PG&E initiated a pole loading program to evaluate whether a pole meets GO 95, Rule 44 strength requirements throughout its service life. This evaluation includes both when the pole was initially installed and while in service.

During a pole's service life, pole loading calculations are performed when load is added to a pole or if a suspected overload condition is observed during inspection. PG&E created a centralized database to retain pole loading calculation record information in accordance with D.09-08-029. LiDAR data is used to accurately locate the pole in relation to surrounding assets, as well as provide measurements for assets attached to

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84 The supporting document is available at: PG&E's Community Wildfire Safety Program.

the pole (i.e., heights and angles of conductor, clearances between conductors, etc.). This LiDAR data is used as an input when performing pole loading calculations, which enables operational decisions from a desktop, reducing field visits, and improving efficiency and safety.

Performing pole loading calculations identifies poles that are overloaded, which increases the probability of failure. PG&E also determines where the overloaded poles are located and can compare that to the wildfire ignition consequence profiles to aid in prioritization efforts.

8.3.12.2 Frequency or Trigger

PG&E has completed the data capture for the LiDAR Pole Loading inspections and does not anticipate completing additional LiDAR Pole Loading inspections.

8.3.12.3 Accomplishments, Roadblocks, and Updates

PG&E has completed the data capture related to the LiDAR Pole Loading Inspection Program. Its measure of success was the collection of LiDAR imagery for all poles in HFTD/HFRA. No additional LiDAR Pole Loading inspections are anticipated. Thus, no targets are set for this program.

8.3.13 Distribution – Overhead Equipment Inspections Program

Tracking ID: N/A

8.3.13.1 Overview

Overhead equipment functional testing and inspection are performed on capacitor banks, fault indicators, interrupters, reclosers, voltage regulators, SCADA, Primary Distribution Alarm and Control controls, and sectionalizers. The program is governed by utility procedure TD-2302P-05,[85] which requires that preventive maintenance activities be conducted in accordance with applicable PG&E, manufacturer, and engineering requirements.

Key components of these equipment inspections and tests include:

- Testing and ensuring capacitors are fully functional prior to summer peaks;
- Testing and ensuring all line reclosers and automatic switches have fully charged batteries and are fully functional; and
- Testing and ensuring all SCADA devices are fully communicating and operable.

Equipment inspections are functional tests focused on operational needs rather than detecting component failures that could result in an ignition. Given the focus on

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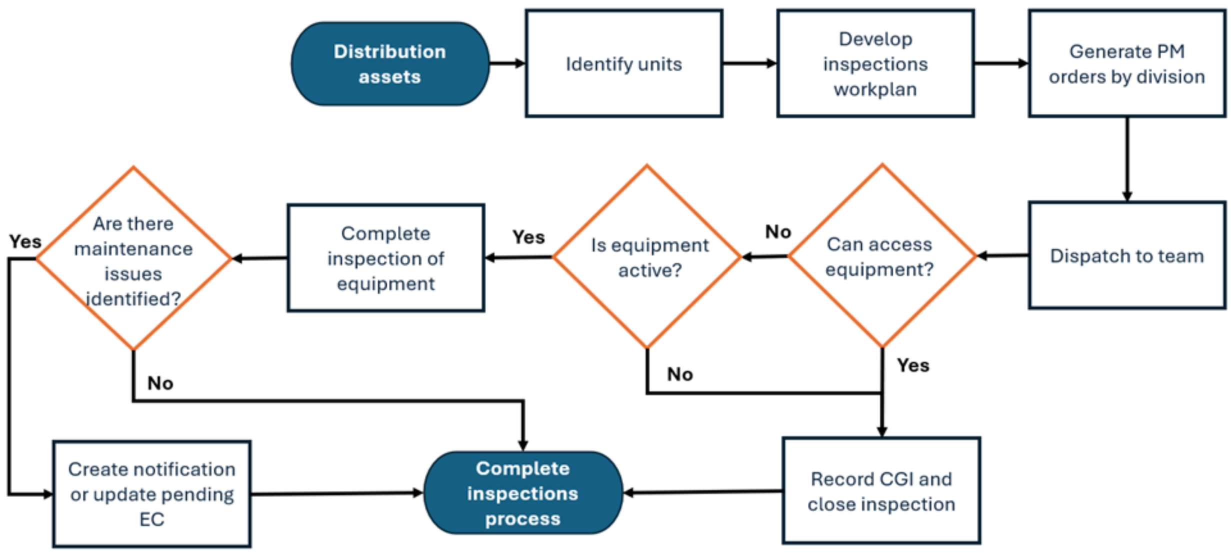
85 The supporting document is available at: PG&E's Community Wildfire Safety Program.

operational needs rather than ignition detection, PG&E has not provided quarterly targets for this program.

Figure 8-1-7 below shows our equipment inspections workflow.

FIGURE 8-1-7:
EQUIPMENT INSPECTIONS WORKFLOW



8.3.12.2 Frequency or Trigger

All eligible equipment is inspected every year, regardless of whether it is located in an HFTD/HFRA. The inspections are functional tests focused on operational needs rather than on preventing ignitions.

8.3.13.3 Accomplishments, Roadblocks, and Updates

This inspection program measures success based on completion of inspections of overhead equipment as outlined in the Electric Distribution Maintenance Requirements for Miscellaneous Overhead and Underground Equipment Procedure (TD-2302P-05).[86]

PG&E's roadblocks continue to be weather and access.

PG&E will perform all miscellaneous overhead inspections annually as detailed in the Electric Distribution Maintenance Requirements for Miscellaneous Overhead and Underground Equipment Procedure (TD-2302P-05).

8.3.14 Distribution – Pilot Inspections Program

Tracking ID: N/A

86 The supporting document is available at: PG&E's Community Wildfire Safety Program.

8.3.14.1 Overview

The Aerial Inspection Program has ended the pilot stage and is described in Section 8.3.8 Detailed Inspection Program.

As noted in Section 8.3.8.3, PG&E will be piloting various sensors that can detect real-time risk on our assets. Real-time sensing devices provide situational intelligence on the structure by signaling that there are damages that can lead to ignition and/or outages. Once the remote sensing technology and the operational integration matures, PG&E will integrate them into our inspection planning process, leveraging these devices to get continuous information on risk and reduce the need for extra visits to structures in between detailed inspections.

8.3.14.2 Frequency or Trigger

Please see Section 8.3.8 Detailed Inspection Program

8.3.14.3 Accomplishments, Roadblocks, and Updates

The measure of success for this initiative is the execution of a sensor pilot within the 2026-2028 period and an evaluation on how sensors can be integrated into the distribution inspections program.

PG&E does not anticipate any major roadblocks to the execution of a sensor pilot.

The Aerial Inspection program provided insight into high-risk compelling issues. The Aerial Inspection Program is now part of Section 8.3.8 Detailed Inspection Program.

8.3.15 Substation Inspection Program

Tracking ID: N/A

8.3.15.1 Overview

The Routine Substation Inspection Program includes three methods of inspection: ground-based inspections, infrared inspections, and drone-based aerial inspections for power generation switchyards and distribution and transmission substations. Ground inspections are a foot patrol designed to identify equipment and station issues that may impact reliability, the environment, physical security, or pose an ignition risk. Infrared (IR) inspections are performed by foot patrol and designed to detect thermal anomalies or “hot spots” as a part of the routine inspections process. Drone inspections are designed to detect equipment-related defects not visible through other inspection methods and vantage points such as ground-based inspections.

Table PG&E-8.3.15.1-1 depicts the drone inspection find rates for substations and switchyards by EC tag designation (A, B, or E).

TABLE PG&E-8.3.15.1-1:
SUBSTATION AND SWITCHYARD DRONE INSPECTION FIND RATE BY YEAR AND NOTIFICATION PRIORITY

Year	A (Percentage)	B (Percentage)	E (Percentage)
2024	0.616%	9.531%	29.370%
2023	0.228%	3.596%	6.193%
2022	1.445%	3.275%	6.090%

8.3.15.2 Frequency or Trigger

Ground inspections are performed at all stations at a maximum interval of once every two months. Infrared inspections are performed at a minimum interval of once annually.

In total, approximately 60 percent of substations and switchyards within HFTD/HFRA are inspected using drones—annually.

The baseline inspection frequency accounts for approximately 33 percent of annual inspections + Risk-based. In-year inspections typically account for approximately an additional 27 percent of the combined substations and power generation switchyards located within the Zone 1, Tier 2, Tier 3 HFTD, or HFRA inspected annually.

Drone-based inspections are performed at substations and power generation switchyards classified as Zone 1, HFTD Tier 2, Tier 3 or HFRA at least once every three years. In general, PG&E performs substation drone inspections in HFTD/HFRA areas earlier in the year to provide time for necessary to execute repairs prior to peak fire season.

8.3.15.3 Accomplishments, Roadblocks, and Updates

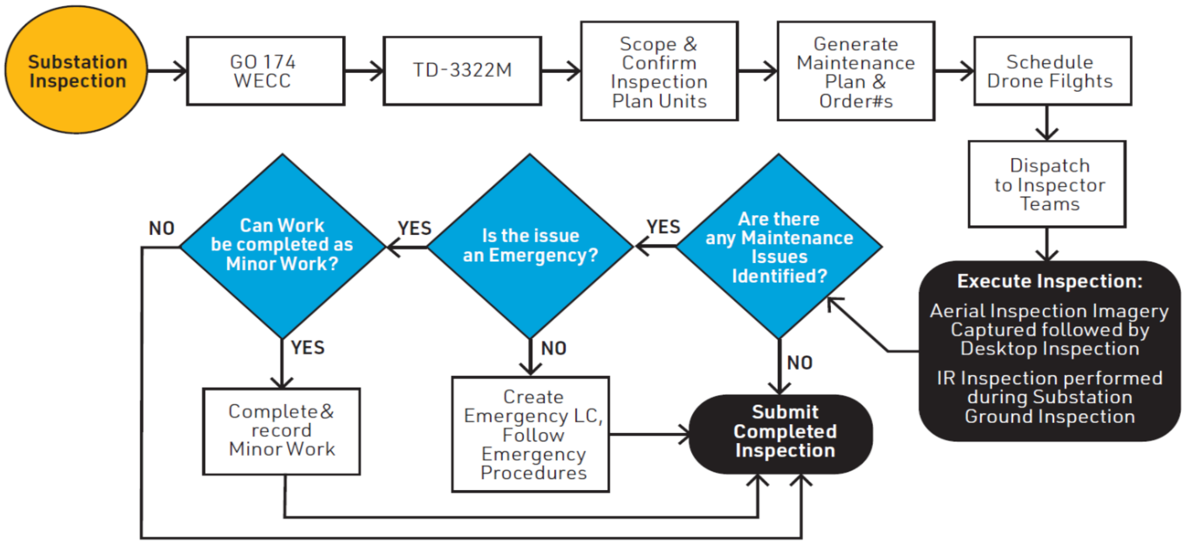
The aerial inspections program continues to detect issues and findings from perspectives otherwise undetectable from the ground. Aerial drone inspections were one element of the former Supplemental Substation Inspection Program and have now been incorporated into the routine program as an enhancement. (See Section 13.3 Discontinued Initiative Activities for details regarding the former program).

PG&E continues to evaluate the effectiveness of inspections findings compared to other detection methods.

There are currently no significant roadblocks.

Figure 8-1-8 depicts PG&E's substation inspection process.

FIGURE 8-1-8:
SUBSTATION INSPECTION PROCESS



8.4 Equipment Maintenance and Repair

In this section, in addition to the information described above regarding distribution, transmission, and substation inspections, the electrical corporation must provide a brief narrative of maintenance activities (programs).[87] *As a narrative, the electrical corporation must include its strategy for maintenance, such as whether the electrical corporation replaces or upgrades facilities/equipment proactively (for example, an electrical corporation may monitor dissolved gases in its transformers to detect potential transformer failures to alert engineering and maintenance personnel or component lifecycle management) or if it runs its facilities/equipment to failure. The narrative must include, at minimum, the following types of equipment:*

1) *Capacitors;*
2) *Circuit breakers;*
3) *Connectors, including hotline clamps;*
4) *Conductor, including covered conductor;*
5) *Fuses, including expulsion fuses;*
6) *Distribution pole;*
7) *Lightning arrestors;*

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87 *Pub. Util. Code §§ 8386(c)(3), (10).*

8) Reclosers;

9) Splices;

10) Transmission poles/towers;

11) Transformers;

12) Non-exempt[88] equipment;

13) Pre-GO 95 legacy equipment; and

14) Other equipment not listed.

For equipment Types 12-14 above, the electrical corporation must include sub-categories for each relevant equipment type. For each equipment type, the electrical corporation must include sections for the following information:

- *Condition Monitoring: A description of how the electrical corporation monitors the condition of the equipment (e.g., human visual inspection, automated visual inspection, human sensor readings, automated sensor readings);*
- *Maintenance Strategy: Identification and brief description of the maintenance strategy (e.g., reactive, preventative, predictive, reliability-centered);*
- *Replacement/Repair Condition: A description of how equipment is identified for repair or replacement (e.g., time interval, inspection finding, sensor reading, predictive maintenance, data analytics, machine learning);*
- *Timeframe for Remediation: A list of possible conditions and findings, including the priority level and associated timeframes for remediation of each;*
- *Failure Rate: The number of total failures attributed to the given equipment type in the HFTD and HFRA[89] during the three calendar years prior to the base WMP submission, broken out by distribution, transmission, and substation. The failure rate must include the likelihood of failure based on the ratio of number of failures to the number of total assets in-field within the HFTD/HFRA for the equipment type;*
- *Ignition Rate: The total number of CPUC-reportable ignitions attributed to the equipment type in the HFTD and HFRA during the 10 calendar years prior to the base WMP submission, broken out by distribution, transmission, and substation. The ignition rate must include evaluation of the likelihood that an equipment failure*

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88 *"Non-exempt" in this instance pertaining to equipment that must comply with clearances specified within Public Resources Code (PRC) § 4292 and PRC § 4293.*

89 *Equipment that falls in both the HFTD and HFRA should not be counted twice. The number of failures should include all equipment that is in the HFTD Tier 2 and 3 and all equipment that is in the utility defined HFRA beyond the HFTD.*

will propagate into an ignition based on the ratio of the number of failures to the number of ignitions attributed to the equipment type; and

- *Failure and Ignition Causes: A narrative describing root cause analyses performed for failures and associated CPUC ignitions within the HFTD and HFRA, including any lessons learned and solutions implemented to decrease ignition rates.*

Table PG&E-8.4-1 below shows our equipment maintenance and repair failure and ignition rates.

TABLE PG&E-8.4-1:
EQUIPMENT MAINTENANCE AND REPAIR

Equipment Type[a]	Failure Rate in HFTD (failures/1k assets/year) 2022-2024	CPUC Reportable Ignition Rate in HFTD (ignitions/failure) 2014-2024
8.4.1 – Capacitors	D: 0.324	D: N/A
8.4.2 – Circuit Breakers	S(D): 0.182 S(T): 0.086	S(D): N/A S(T): N/A
8.4.3 – Connectors, Including Hotline Clamps	D: 0.901 T: 0.435	D: 0.060 T: 0.105
8.4.4 – Conductor, Including Covered Conductor	D: 0.901 T: 0.435	D: 0.060 T: 0.105
8.4.5 – Fuses, Including Expulsion Fuses	D: N/A	D: N/A
8.4.6 – Distribution Pole	D: 0.388	D: 0.015
8.4.7 – Lightning Arrestors	D: 0.010	D: 0.044
8.4.8 – Reclosers	D: 1.279	D: 0.083
8.4.9 – Splices	D: 0.901 T: 0.435	D: 0.060 T: 0.105
8.4.10 – Transmission Poles/Towers	T: 0.045	T: 0.040
8.4.11 – Distribution Transformers	D: 3.297	D: 0.008
8.4.12 – Non-Exempt Equipment	N/A	N/A
8.4.13 – Pre-GO 95 Legacy Equipment	D: N/A	D: N/A
8.4.14 – Other Equipment Not Listed	T (Switch): 2.217 T (Insulator): 0.162 D (All Other): 0.865	T (Switch): 0.111 T (Insulator): 0.075 D (All Other): 0.017

(a) See specific Equipment Type sections for the nature of calculations.

Rates may not be representative of current state of risk in some cases due to mitigations implemented such as EPSS, PSPS, and equipment replacement programs.

8.4.1 Capacitors

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

All distribution capacitors are annually inspected as part of the Distribution Overhead Equipment Inspection Program. The procedure is described in Section 8.3. The annual inspections and testing are completed before the peak load season starts.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

The capacitors that fail inspection are flagged as inoperable during inspection and taken out of service. The replacement and repair of the out-of-service units are prioritized based on reliability impact.

Timeframe for Remediation

Guidance for the timeframe for remediation of conditions arising from inspections is defined in TD-2305M[90] and applicable job aids.

Failure Rate

Failures for distribution assets were calculated as emergency (A) tags with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc., were excluded as non-equipment failures. The failure rate was calculated as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA capacitors in the system (capacitor count from 2024) per year. See Table PG&E-8.4-1 above for tabulated failure rates.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in

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90 The supporting document is available at: PG&E's Community Wildfire Safety Program.

HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC reportable ignitions in the HFTD. The process is documented in RISK-6306P-02.[91] The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable. Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and (d) unknown. The cause of HFTD or HFRA capacitor failures from 2022-2024 are broken down as follows:

- Equipment Failed – 100 percent;
- Pole Rotten – 0 percent;
- Other – 0 percent; and
- Unknown – 0 percent.

Causes of the capacitor ignitions fall into one of two categories: Equipment – Failed or Equipment – Overloaded. The causes of HFTD or HFRA capacitor ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 88 percent; and
- Equipment – Overloaded – 13 percent

8.4.2 Circuit Breakers

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☐	Substation ☒

Tracking ID: N/A

Condition Monitoring

Substation circuit breakers are inspected and maintained in accordance with Utility Standard Substation Equipment Maintenance Requirements (TD-3322S, Attachment 7),[92] which includes provisions for inspections and preventive time-based

91 The supporting document is available at: PG&E's Community Wildfire Safety Program.

92 The supporting document is available at: PG&E's Community Wildfire Safety Program.

and condition-based maintenance. Requisite maintenance tasks include mechanism service, diagnostic testing, compressor service, overhaul, routine exercise, and sampling insulating media such as SF6 gas or mineral oil analyses for quality and dissolved gases. In general, standardized substation maintenance intervals vary from annual, bi-annual, 4-years, 8-years, or 12-years, based on circuit breaker type and application. Since the program also uses condition-based triggers such as oil sample results to initiate additional maintenance tasks, the intervals are not always linear and the frequencies between maintenance tasks may vary.

Maintenance Strategy

Preventative ☒	**Predictive ☐**	**Reliability-Centered ☐**	**Reactive**
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Substation circuit breaker maintenance tasks are prioritized based on cyclical time triggers and actual equipment condition. Circuit breakers are replaced using one of these replacement triggers: emergency in-service failure; Just-in-Time (JIT) replacement based on condition; and capacity improvement replacements. Wildfire risk is considered in the decision whether to repair or replace circuit breakers.

As part of the EPSS Program, PG&E has also identified instances of circuit breaker incompatibility with the EPSS relaying devices. These circuit breaker replacements are necessary when older legacy styles of circuit breakers are not compatible with modern microprocessor relays such as those used with EPSS schemes.

In Power Generation switchyards, PG&E also applies a proactive maintenance strategy for circuit breakers where maintenance tasks are prioritized based on time and condition based triggers. The replacement strategies for circuit breakers in switchyards focus on emergency in-service failures and JIT replacements based on condition.

Replacement/Repair Condition

PG&E’s substation circuit breaker maintenance and replacement program is designed to ensure that circuit breakers are properly installed and maintained to prevent operational failures. A circuit breaker failure could result in an increased risk of ignition because improper or delayed circuit breaker operation can increase the time it takes to interrupt a line or bus fault. Operational failure can also impact reliability because it would take longer to restore power after an outage. Improperly maintained circuit breakers are prone to malfunction or slow operation. The risk of a slow trip operation or failure of a circuit breaker to operate could result in an increased probability of an ignition event both inside and outside of substations.

PG&E also replaces circuit breakers on a risk-based proactive and emergency basis. Proactive replacement is based largely on condition and historical circuit breaker failure rates using a prioritization model. The prioritization model includes overstress, age, and interrupting media for oil, SF6, and vacuum circuit breakers.

In general, substation emergency equipment replacements are tracked in two categories: (1) replacement of equipment that has failed in service; and (2) replacement of equipment intentionally removed from service (forced out) because we determine that imminent failure is likely to occur (also known as JIT replacement). Equipment that is forced out of service avoids in service failures that may result in safety impacts, equipment failure, sustained outages, collateral damage, and environmental impacts. Power Generation does not track emergency equipment replacements in switchyards due to the small asset inventory and low number of occurrences.

Timeframe for Remediation

The circuit breaker inspection and maintenance programs include several checkpoints to ensure performance and health are acceptable. Findings from inspections and maintenance are consistent with those listed within Utility Standard TD-3322S,[93] "Substation Equipment Maintenance Requirements," which includes associated priority levels for repair.

Failure Rate

Failure rates were calculated assessing circuit breakers requiring the capital replacement of the asset caused by failure of the mechanism, interrupter, bushing, insulating medium, or animal contact. The failure rate was calculated as the number of HFTD or HFRA circuit breaker failures divided by the number of known HFTD or HFRA circuit breakers in the system (circuit breaker count from 2024) over the years in scope. Both catastrophic and non-catastrophic as defined below were considered to derive the failure rate. See Table PG&E-8.4-1 for tabulated failure rates.

In-Service Failure: Any asset that fails to operate as designed while in-service and is then replaced.

Catastrophic Failure: An asset failure is classified as a catastrophic failure if it meets the definition of in-service failure and results in any combination of an explosion, fire, tank rupture that results in pressure release (oil, gas, shrapnel etc.).

Ignition Rate

There were no substation circuit breaker ignitions from 2014-2024 in HFTD or HFRA that were CPUC reportable ignitions caused by equipment failure or overload and utility operation.

Failure and Ignition Causes

Failure and ignition causes include mechanisms failing to operate as designed due to compromised components, interrupters failing due to electrical stress exceeding the designed insulation limits of the equipment, or animal contact resulting in the overall failure of the circuit breaker.

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93 The supporting document is available at: PG&E's Community Wildfire Safety Program.

8.4.3 Connectors, Including Hotline Clamps

8.4.3.1 Distribution Connectors, Including Hotline Clamps

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: GM-14 (See Section 8.2.10.6 for more information on our target related to SB Connector installations.)

Condition Monitoring

Connectors (including hotline clamps) are visually inspected as part of the detailed overhead inspection and aerial inspection programs. Detailed overhead inspections are both risk and compliance driven as described in Section 8.3. Some of the connector conditions that are monitored include corrosion, physical damage, wrong connector type, and insufficient clearance. A full list of conditions that are monitored are defined in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[94]

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

Connectors that failed inspections are fixed by replacing the connector. The findings are addressed in a risk prioritized manner as described in Section 8.6 through the Electric Corrective (EC) tag process.

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-2305M and applicable job aids.

Failure Rate

Failures of distribution connectors generally are not tracked separately from failures associated with conductor (Section 8.4.4) and splices (Section 8.4.9). A single combined failure rate is provided for failures of these three equipment types in Table PG&E-8.4-1. Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an

94 The supporting document is available at: PG&E's Community Wildfire Safety Program.

inspection) were excluded as inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc., were excluded as non-equipment failures. The failure rate was calculated as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA structures in the system (structure count from 2024) per year.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. A combined rate was calculated for connectors and splices, as these are not collected separately. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC-reportable ignitions. The process is documented in RISK-6306P-02. The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable. Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and d) unknown. The cause of HFTD or HFRA connectors, conductor, or splice failures from 2022-2024 are broken down as follows:

- Equipment Failed – 51 percent;
- Pole Rotten – 0 percent;
- Other – 17 percent; and
- Unknown – 32 percent.

Causes of the distribution connector and splice ignitions fall into one of three categories: Equipment – Failed, Equipment – Overloaded, or Utility Operation. The causes of HFTD or HFRA connector and splice ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 84 percent;
- Equipment – Overloaded – 7 percent; and
- Utility Operation – 9 percent.

8.4.3.2 Transmission Connectors, Including Hotline Clamps

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☒	Substation ☐

Condition Monitoring

Maintenance of transmission connectors is typically triggered via detailed overhead inspections and patrols. Detailed overhead inspections are both risk and compliance driven, performed as described in Section 8.3. Inspections related to connectors include detailed, climbing, and infrared.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Maintenance on connectors is mainly driven by inspection findings, which are prioritized as described in Section 8.6. Sampling and testing will inform future maintenance requirements.

Replacement/Repair Condition

Typically, maintenance activities include repair, replacement, or removal. The maintenance activity is determined using TD-1001M, TD-8123P-103, job aids, and applicable standards.[95]

Timeframe for Remediation

The timeframe for remediation is defined in TD-8123P-103 and applicable job aids.

Failure Rate

Failures of transmission connectors generally are not tracked separately from failures associated with conductor (Section 8.4.4) and splices (Section 8.4.9). A single combined failure rate is provided for failures of these three equipment types in Table PG&E-8.4-1. Failure rate is calculated as HFTD or HFRA outages per HFTD or HFRA structure per year (structure count from 2024). Outages attributed to equipment failure, weather (except lightning), contamination, and unknown/other are included. Note that outages due to vegetation and third-party damage are not included.

95 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

Ignition Rate

Ignitions for transmission assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. A combined rate was calculated for connectors, splices, conductors, jumpers, and tie wire, as failures for these components are not collected separately. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

Asset-caused failures are assessed to determine level of causal evaluation needed. Both ignition and non-ignition events are included in processes documented through RISK-6306P-02 and TD-1050P-01.[96] Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Causes of the transmission connector and splice ignitions fall into one category: Equipment – Failed. The causes of HFTD or HFRA connector and splice ignitions from 2014-2024 are broken down as follows:

Equipment – Failed – 100 percent.

8.4.4 Conductor, Including Covered Conductor

8.4.4.1 Distribution Conductors (including Covered Conductor (CC))

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

Conductors (including CCs) are visually inspected as part of the detailed overhead inspections and aerial inspections. Detailed overhead inspections are both risk and compliance driven and performed as described in Section 8.3. A full list of conditions that are monitored are in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[97]

96 The supporting document is available at: PG&E's Community Wildfire Safety Program.

97 The supporting document is available at: PG&E's Community Wildfire Safety Program.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

Conductor issues are fixed by replacing or repairing the conductor. The findings are addressed in a risk prioritized manner as described in Section 8.6 through the EC tag process.

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-2305M[98] and applicable job aids.

Failure Rate

Failures of distribution conductors generally are not tracked separately from failures associated with connectors (Section 8.4.3) and splices (Section 8.4.9). A single combined failure rate is provided for failures of these three equipment types in Table PG&E-8.4-1. Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc., were excluded as non-equipment failures. The failure rate was calculated as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA structures in the system (structure count from 2024) per year.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC-reportable ignitions caused from equipment failure or vegetation contact. The process is documented in RISK-6306P-02.

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98 The supporting document is available at: PG&E's Community Wildfire Safety Program.

The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable. Lessons learned from these failures are documented in ACI PG&E-22-08.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and (d) unknown. The cause of HFTD or HFRA connectors, conductor, or splice failures from 2022-2024 are broken down as follows:

- Equipment Failed – 51 percent;
- Pole Rotten – 0 percent;
- Other – 17 percent; and
- Unknown – 32 percent.

Causes of the distribution conductor ignitions fall into one of four categories: Equipment – Failed, Equipment – Overloaded, Utility Operation, or Wire-Wire Contact. The causes of HFTD or HFRA conductor ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 74 percent;
- Equipment – Overloaded – 13 percent;
- Utility Operation – 8 percent; and
- Wire-Wire Contact – 5 percent.

8.4.4.2 Transmission Conductors (including CCs)

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☒	Substation ☐

Condition Monitoring

Maintenance of conductors is typically triggered via detailed overhead inspections and patrol. Detailed overhead inspections are both risk and compliance driven, performed as described in Section 8.3. Inspections related to conductors include detailed, infrared, and pilot programs including conductor measurement, sampling, and testing.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Maintenance on conductors is mainly driven by inspection findings, which are prioritized as described in Section 8.6 . Maintenance on conductors can occur because of inspection findings or with input from an engineering assessment.

Pilot inspection, sampling, and testing will inform future maintenance requirements.

Replacement/Repair Condition

Typically, maintenance activities include repair, replacement, or removal. The maintenance activity is determined using TD-1001M, TD-8123P-103, job aids, and applicable standards.[99]

Timeframe for Remediation

The timeframe for remediation is defined in TD-8123P-103 and applicable job aids.

Failure Rate

Failures of transmission conductors generally are not tracked separately from failures associated with connectors (Section 8.4.3) and splices (Section 8.4.9). A single combined failure rate is provided for failures of these three equipment types in Table PG&E-8.4-1. Failure rate is calculated as HFTD or HFRA outages per HFTD or HFRA structure per year (structure count from 2024). Outages attributed to equipment failure, weather (except lightning), contamination, and unknown/other are included. Note that outages due to vegetation and third-party damage are not included.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. A combined rate was calculated for connectors, splices, conductors, jumpers, and tie wire, as failures for these components are not collected separately. See Table PG&E-8.4-1 for tabulated ignition rates.

99 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

Failure and Ignition Causes

Asset-caused failures are assessed to determine level of causal evaluation needed. Both ignition and non-ignition events are included in processes documented through RISK-6306P-02 and TD-1050P-01. Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Causes of the transmission conductor ignitions fall into one of two categories: Equipment – Failed or Equipment – Overloaded. The causes of HFTD or HFRA conductor ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 94 percent; and
- Equipment – Overloaded – 6 percent.

8.4.5 Fuses, Including Expulsion Fuses

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

Expulsion fuses are visually inspected as part of the detailed overhead and aerial inspections. Detailed overhead inspections are both risk and compliance driven and performed as described in Section 8.3. Some of the fuse conditions that are monitored include broken/damaged cutouts, Liquid Fuse with no liquid, Liquid Fuse with low oil level, and fuse end fitting corroded. A full list of conditions that are monitored are in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[100]

In addition, PG&E performs infrared detailed overhead inspections of distribution electric lines and equipment in the HFTD (Section 8.3.8) to detect abnormal hot spots on equipment using infrared imaging and temperature measuring systems. Excessive heating gradients on fuses are a potential sign of equipment failure.

Maintenance Strategy

Preventative ☒	**Predictive** ☐	**Reliability-Centered** ☐	**Reactive** ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

The issues found through the inspection programs are addressed in a risk prioritized manner as described in Section 8.6 through the EC tag process. For the proactive replacement program, the locations for replacement are prioritized based on the wildfire consequence of the geo location.

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-2305M and applicable job aids.

Failure Rate

Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as

100 The supporting document is available at: PG&E's Community Wildfire Safety Program.

inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc. were excluded as non-equipment failures. The failure rate was calculated as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA fuses in the system (fuse count from 2024) per year. See Table PG&E-8.4-1 for tabulated failure rates.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC-reportable ignitions caused from equipment failure or vegetation contact. The process is documented in RISK-6306P-02. The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable. Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and (d) unknown. The cause of HFTD or HFRA fuse failures from 2022-2024 are broken down as follows:

- Equipment Failed – 38 percent;
- Pole Rotten – 0 percent;
- Other – 31 percent; and
- Unknown – 31 percent.

Causes of the distribution fuse ignitions fall into one of three categories: Equipment – Failed, Utility Operation, or Contamination. The causes of HFTD or HFRA fuse ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 90 percent;
- Utility Operation – 5 percent; and
- Contamination – 5 percent.

8.4.6 Distribution Pole

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

Distribution poles are visually inspected as part of the detailed overhead inspection and aerial inspection programs. Additionally, intrusive inspections of wood poles are conducted as part of the PT&T Program. Inspections are both risk and compliance driven and are performed as described in Section 8.3. Some of the pole conditions that are monitored include broken/damaged, split, visually deteriorated, leaning, woodpecker damage, deformed, and overstressed. A full list of conditions that are monitored are defined in TD-2305M-JA02.[101]

Also included are poles that are identified as potentially overloaded through system inspections or the pole loading assessment as described in Section 8.3.8.

Maintenance Strategy

Preventative ☒	**Predictive** ☐	**Reliability-Centered** ☐	**Reactive** ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

Pole issues, including overloaded poles, are fixed by replacing, stubbing or reinforcing the pole. The findings are addressed in a risk prioritized manner as described in Section 8.6 through the EC tag process.

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-2305M[102] and applicable job aids.

Failure Rate

Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as

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101 The supporting document is available at: PG&E's Community Wildfire Safety Program.

102 The supporting document is available at: PG&E's Community Wildfire Safety Program.

inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc. were excluded as non-equipment failures. The failure rate was calculated as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA poles in the system (pole count from 2024) per year. See Table PG&E-8.4-1 for tabulated failure rates.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC-reportable ignitions caused from equipment failure or vegetation contact. The process is documented in RISK-6306P-02. The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable. Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and (d) unknown. The cause of HFTD or HFRA distribution pole failures from 2022-2024 are broken down as follows:

- Equipment Failed – 37 percent;
- Pole Rotten – 22 percent;
- Other – 26 percent; and
- Unknown – 15 percent.

Causes of the distribution pole ignitions fall into one of three categories: Equipment – Failed, Utility Operation, or Contamination. The causes of HFTD or HFRA distribution pole ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 85 percent;
- Utility Operation – 5 percent; and
- Contamination – 10 percent.

8.4.7 Lightning Arrestors

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

Lightning arrestors are visually inspected as part of the detailed overhead inspection and aerial inspection programs. Detailed overhead inspections are both risk and compliance driven and are performed as described in Section 8.3. Some of the lightning arrestor conditions that are monitored include those that are broken and/or flashed. A full list of conditions that are monitored are defined in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[103]

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

Lightning arrestor issues identified during inspection are fixed by proactively replacing the arrestors prior to failure. The findings are addressed in a risk prioritized manner as described in Section 8.6 through the EC tag process.

We completed the proactive replacement of the known population of non-exempt surge arresters with deficient grounding in the HFTD and HFRA in 2024. See Section 8.2.10.4 for more information.

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-2305M and applicable job aids.

Failure Rate

Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc. were excluded as non-equipment failures. The failure rate was calculated

[103] The supporting document is available at: PG&E's Community Wildfire Safety Program.

as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA structures in the system (structure count from 2024) per year. See Table PG&E-8.4-1 for tabulated failure rates.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC-reportable ignitions caused from equipment failure or vegetation contact. The process is documented in RISK-6306P-02. The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable. Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and (d) unknown. The cause of HFTD or HFRA lightning arrestor failures from 2022-2024 are broken down as follows:

- Equipment Failed – 68 percent;
- Pole Rotten – 0 percent;
- Other – 11 percent; and
- Unknown – 21 percent.

Causes of the distribution lightning arrestor ignitions fall into one category: Equipment – Failed. The causes of HFTD or HFRA lightning arrestor ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 100 percent.

8.4.8 Reclosers

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

All distribution reclosers are annually inspected as part of the Distribution Overhead Equipment Inspection Program. The procedure is described in Section 8.3.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☒	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

Reclosers that fail inspection or fail to operate during normal operations are flagged as inoperable and taken out of service. The replacement and repair of the out of service units are prioritized based on EPSS and reliability impacts.

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-2305M[104] and applicable job aids.

Failure Rate

Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc. were excluded as non-equipment failures. The failure rate was calculated as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA reclosers and sectionalizers in the system (reclosers/sectionalizers count from 2024) per year. See Table PG&E-8.4-1 for tabulated failure rates.

[104] The supporting document is available at: PG&E's Community Wildfire Safety Program.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC-reportable ignitions caused from equipment failure or vegetation contact. The process is documented in RISK-6306P-02. The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable. Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and (d) unknown. The cause of HFTD or HFRA recloser and sectionalizer failures from 2022-2024 are broken down as follows:

- Equipment Failed – 89 percent;
- Pole Rotten – 0 percent;
- Other – 0 percent; and
- Unknown – 11 percent.

Causes of the distribution recloser ignitions fall into one category: Equipment – Failed. The causes of HFTD or HFRA recloser ignitions from 2014-2024 are broken down as follows:

Equipment – Failed – 100 percent.

8.4.9 Splices

8.4.9.1 Distribution Splices

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

Splices are visually inspected as part of the detailed overhead inspection and aerial inspection programs. Detailed overhead inspections are both risk and compliance driven, performed as described in Section 8.3.

Maintenance Strategy

Preventative ☒ Targeted program in place for identification of conditions and addressing the condition before failure.	**Predictive ☐** Targeted program in place to actively address risk before it is realized.	**Reliability-Centered ☐** Targeted program in place to analyze assets and maintain critical asset functionality.	**Reactive ☐** Replacement or repair of component after failure.

Splice issues are fixed by replacing the splice. The findings are addressed in a risk prioritized manner as described in Section 8.6.2 through the EC tag process.

Replacement/Repair Condition

A full list of compelling conditions that are evaluated (cracked, corroded, damaged, etc.) and how they are tagged and prioritized for repair are defined in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[105]

Timeframe for Remediation

Compelling conditions (cracked, corroded, damaged, etc.) are prioritized for repair as set forth in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).

Failure Rate

Failures of distribution splices generally are not tracked separately from failures associated with connectors (Section 8.4.3) and conductor (Section 8.4.4). A single combined failure rate is provided for failures of these three equipment types in Table PG&E-8.4-1. Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc. were excluded as non-equipment failures. The failure rate was calculated as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA structures in the system (structure count from 2024) per year.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures

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105 The supporting document is available at: PG&E's Community Wildfire Safety Program.

per year. A combined rate was calculated for connectors and splices, as these are not collected separately. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC reportable ignitions caused from equipment failure or vegetation contact. The process is documented in RISK-6306P-02. The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and (d) unknown. The cause of HFTD or HFRA connectors, conductor, or splice failures from 2022 to 2024 are broken down as follows:

- Equipment Failed – 51 percent;
- Pole Rotten – 0 percent;
- Other – 17 percent; and
- Unknown – 32 percent.

Causes of the distribution connector and splice ignitions fall into one of three categories: Equipment – Failed, Equipment – Overloaded, or Utility Operation. The causes of HFTD or HFRA connector and splice ignitions from 2014 to 2024 are broken down as follows:

- Equipment – Failed – 84 percent;
- Equipment – Overloaded – 7 percent; and
- Utility Operation – 9 percent.

8.4.9.2 Transmission Splices

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☒	Substation ☐

Tracking ID: N/A

Condition Monitoring

Transmission splice maintenance is primarily identified through detailed overhead inspections and patrols. Detailed overhead inspections are both risk and compliance driven, performed as described in Section 8.3. Inspections specific to addressing splices include detailed and infrared.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Shunt splice installation, which provides protection around existing splices for conductor strength reinforcement, can be used as a short-term mitigation for conductor failure risk. Splices may also be proactively replaced as part of other asset replacement work.

From 2026-2028, transmission lines will continue to be targeted for splice shunt installation (See target GH-06 in Section 8.1). Additionally, sampling and testing conducted during this period will inform future maintenance requirements.

Maintenance on splices also can be driven by inspection findings.

Replacement/Repair Condition

Typically, maintenance activities arising from inspection findings include repair, replacement, or removal. The maintenance activity is determined using TD-1001M, TD-8123P-103, job aids, and applicable standards.[106]

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-8123P-103 and applicable job aids.

Failure Rate

Failures of transmission splices generally are not tracked separately from failures associated with connectors (Section 8.4.3) and conductor (Section 8.4.4). A single combined failure rate is provided for failures of these three equipment types in Table PG&E-8.4-1. Failure rate is calculated as HFTD or HFRA outages per HFTD or HFRA structure per year (structure count from 2024). Outages attributed to equipment failure, weather (except lightning), contamination, and unknown/other are included. Note that outages due to vegetation and third-party damage are not included.

Ignition Rate

Ignitions for transmission assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism,

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[106] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. A combined rate was calculated for connectors and splices, as these are not collected separately. See Table PG&E-8.4-1for tabulated ignition rates.

Failure and Ignition Causes

Asset-caused failures are assessed to determine level of causal evaluation needed. Both ignition and non-ignition events are included in processes documented through RISK-6306P-02 and TD-1050P-01.[107]

Causes of the transmission connector and splice ignitions fall into one category: Equipment – Failed. The causes of HFTD or HFRA connector and splice ignitions from 2014-2024 are broken down as follows:

Equipment – Failed – 100 percent.

8.4.10 Transmission Poles/Towers

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☒	Substation ☐

Tracking ID: N/A

Condition Monitoring

Transmission poles and tower maintenance is primarily identified through inspections and patrols including detailed, climbing, and intrusive pole inspection.

Maintenance Strategy

Preventative ☒	**Predictive ☐**	**Reliability-Centered ☐**	**Reactive ☐**
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Maintenance on poles is mainly driven by inspection findings, which are prioritized as described in Section 8.6.1. Maintenance on towers can occur during inspections or with input from an engineering assessment.

Pilot inspections, sampling, and testing will inform future maintenance requirements.

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[107] The supporting documents are available at: PG&E'S Community Wildfire Safety Program.

Replacement/Repair Condition

Typically, maintenance activities include repair, replacement, or removal. For poles and towers, life extension through pole stubbing, steel coating and cathodic protection may also occur. The maintenance activity is determined using TD-1001M, TD-8123P-103, job aids, and applicable standards.[108]

Timeframe for Remediation

The timeframe for remediation for intrusive inspection findings on wood poles is defined in TD-2325P-01. The timeframe for remediation for other findings is defined in TD-8123P-103 and applicable job aids;[109] timeframes for maintenance on towers also may be informed by input from an engineering assessment.

Failure Rate

The failure rate for transmission structures is provided in Table PG&E-8.4-1. The failure rate calculation includes failures associated with crossarms and structure hardware, which are not generally tracked separately from structure failures. Failure rate is calculated as HFTD or HFRA outages per HFTD or HFRA structure per year (structure count from 2024). Outages attributed to equipment failure, weather (except lightning), contamination, and unknown/other are included. Note that outages due to vegetation and third-party damage are not included.

Ignition Rate

Ignitions for transmission assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

Asset-caused failures are assessed to determine level of causal evaluation needed. Both ignition and non-ignition events are included in processes documented through RISK-6306P-02 and TD-1050P-01.[110] Lessons learned from these failures, for example, are documented in ACI PG&E-22-08.

Causes of the transmission pole ignitions fall into one of two categories: Equipment – Failed or Equipment – Overloaded. The causes of HFTD or HFRA transmission pole ignitions from 2014-2024 are broken down as follows:

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[108] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

[109] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

[110] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

- Equipment – Failed – 50 percent; and
- Equipment – Overloaded – 50 percent.

8.4.11 Transformers

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

Distribution overhead transformers are partly proactively managed and generally run to condition. Detailed overhead inspections are both risk and compliance driven, performed per Section 8.3, and findings may result in replacement or repair. Findings via risk informed- detailed overhead inspections are considered proactive. Findings are addressed as described in Section 8.6.2.

Maintenance Strategy

Preventative ☒	Predictive ☒	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Transformer issues are fixed by replacing the transformer. The findings are addressed in a risk prioritized manner as described in Section 8.6 through the EC tag process.

Please see response to ACI PG&E-25U-05 in Appendix D for information on transformer predictive maintenance and the IONA model.

Replacement/Repair Condition

Some inspections specific to addressing transformer concerns include detailed ground and aerial assessments. Additionally, transformers may be proactively replaced via projects for other drivers, such as system hardening. A full list of conditions that are monitored are defined in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[111]

[111] The supporting document is available at: PG&E's Community Wildfire Safety Program.

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-2305M and applicable job aids.

Failure Rate

Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc. were excluded as non-equipment failures. The failure rate was calculated as the number of HFTD or HFRA failures divided by the number of known HFTD or HFRA transformers in the system (transformer count from 2024) per year. See Table PG&E-8.4-1 for tabulated failure rates.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

PG&E performs a causal review on all CPUC-reportable ignitions caused from equipment failure or vegetation contact. The process is documented in RISK-6306P-02.[112] The findings lead to an evaluation of extent of condition review and corrective actions to mitigate recurrence in the system, when applicable.

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) Other, and (d) Unknown. The cause of HFTD or HFRA transformer failures from 2022-2024 are broken down as follows:

- Equipment Failed – 83 percent;
- Pole Rotten – 0 percent;
- Other – 5 percent; and
- Unknown – 13 percent.

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[112] The supporting document is available at: PG&E's Community Wildfire Safety Program.

Causes of the distribution transformer ignitions fall into one of three categories: Equipment – Failed, Equipment – Overloaded or Contamination. The causes of HFTD or HFRA transformer ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 67 percent;
- Equipment – Overloaded – 30 percent; and
- Contamination – 4 percent.

8.4.12 Non-Exempt Equipment

8.4.12.1 Non-Exempt Fuses

Non-exempt fuses include universal fuses, open link fuses, enclosed cutout with universal fuses, and solid blade disconnect.

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☒	Substation ☒

Tracking ID: N/A

Condition Monitoring

Every line mile in HFTD and HFRA is inspected with the goal of seeking and identifying non-exempt equipment. An accurate inventory of non-exempt equipment is maintained.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

PG&E maintains a minimum firebreak of a 10-foot radius around both distribution and transmission poles with nonexempt equipment. See TD-7112S for maintenance of fire breaks and Guidance Document 015225 for equipment selection process.[113]

[113] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

Replacement/Repair Condition

Certain non-HFTD/non-HFRA locations require non-exempt fuses as the best option for line safety and operation. Locations are assessed by engineering teams to determine the best-suited fuse for each location.

Non-exempt fuses are replaced by non-exempt solid blade disconnects in the event where protection is not needed for that line section, but it is beneficial to maintain a switching point for field operations and restoration efforts.

Per 2023-2025 WMP commitment GH-10, the known population of distribution line protection non-exempt line fuses will be proactively replaced by the end of 2025. As field conditions warrant, fuses are replaced by crews responding to in-service failures.

Timeframe for Remediation

A full list of compelling conditions that are evaluated (cracked, corroded, damaged, etc.) and how they are tagged and prioritized for repair are defined in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[114]

Failure Rate

Due to the intended function of non-exempt fuses, regular operation (as designed) expels molten material or sparks. Thus, data is not available to reliably determine rate of failure. Further, the total number of operations needed to determine failure rate is unknown, because both operations and number of fuses per location would need to be recorded or aggregated.

Ignition Rate

Ignitions due to non-exempt fuses are not collected separately from all fuses. Further, the total number of fuses operations are not tracked accurately. Therefore, it is not possible to provide an ignition rate.

Failure and Ignition Causes

It is important not to confuse non-exempt equipment operations versus failures. Non-exempt equipment labeling is associated with properly installed equipment and the ability to expel hot or molten material upon a normal operation. Failures can occur at a non-exempt equipment location and be associated with other equipment and connections. PG&E's data does not have significant history that captured the details needed for this analysis.

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[114] The supporting document is available at: PG&E’s Community Wildfire Safety Program.

8.4.12.2 Non-Exempt Arresters

Non-exempt arresters include lightning/surge arresters, non-porcelain lightning arresters, and lightning arresters.

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

Every line mile in HFTD and HFRA is inspected with the goal of seeking and identifying non-exempt equipment. An accurate inventory of non-exempt equipment is maintained.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

PG&E maintains a minimum firebreak of a 10-foot radius around both distribution and transmission poles with nonexempt equipment. See TD-7112S for maintenance of fire breaks and Guidance Document 015225 for the equipment selection process.[115]

Replacement/Repair Condition

The known population of non-exempt lightning/surge arresters with potentially deficient grounding will be proactively replaced by the end of 2025. The program addresses locations that have common grounds for the lighting/surge arresters and transformers. The program replaces the non-exempt lightning/surge arresters and separates the grounding for the lighting/surge arresters and transformers. As field conditions warrant, lightning/surge arresters are replaced by crews responding to in-service failures.

Timeframe for Remediation

A full list of compelling conditions that are evaluated (cracked, corroded, damaged, etc.) and how they are tagged and prioritized for repair are defined in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[116]

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115 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

116 The supporting document is available at: PG&E's Community Wildfire Safety Program.

The known population of non-exempt lightning/surge arresters with potentially deficient grounding will be proactively replaced by the end of 2025.

Failure Rate

Failure and ignition for arresters are identical events. Ignitions due to non-exempt arrestors are not collected separately from all arrestors.

Ignition Rate

Failure and ignition for arresters are identical events. Ignitions due to non-exempt arrestors are not collected separately from all arrestors.

Failure and Ignition Causes

Overvoltage events due to overhead transmission conductor failures or compromised grounding lead to arrester failure/ignition. It is important not to confuse non-exempt equipment operations versus failures. Failures can occur at a non-exempt equipment location and be associated with other equipment and connections. PG&E's data does not have significant history that captured the details needed for this analysis.

8.4.12.3 Non-Exempt Clamps

Non-exempt clamps include hot tap clamp and split bolt connectors.

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

All Tap clamps are inspected annually in the high fire threat districts per TD-2305M-JA02 p. 116.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

PG&E maintains a minimum firebreak of a 10-foot radius around both distribution and transmission poles with non-exempt equipment. See TD-7112S for maintenance of fire breaks and Guidance Document 015225 for equipment selection process.[117]

Replacement/Repair Condition

Replacement of non-exempt connectors is done in coordination with conductor replacement. When conductors are upgraded, there is no option to put a non-exempt conductor into service. Only exempt connections may be installed per TD-9001M, "Electric Design Manual" – Chapter 15 15.4 Note 2.

Additionally, per Document 028852 p. 2, when performing work at either the primary or secondary conductor level, all connections at the level being worked are inspected. If any connections are either suspect, failing, or non-exempt (see notes below), the suspect, failing, or non-exempt connector and all other bolted connectors on the circuit at the level being worked (on the structure) are replaced with fired wedge or compression connectors.

Notes: (1) Suspect connectors are connectors that have corrosion; (2) Failing connectors are connectors that show signs of pitting, evidence of burning, or have loose bolts; and (3) Non-exempt connectors include specific hotline clamps without spring

[117] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

tension, copper split bolts which are in active use (not left idle on the line), and some single-bolt vise connectors as described in Section 3 of the Power Line Fire Prevention Field Guide.

Timeframe for Remediation

A full list of compelling conditions that are evaluated (cracked, corroded, damaged, etc.) and how they are tagged and prioritized for repair are defined in the PG&E Overhead Inspection Job Aid (TD-2305M-JA02).[118]

Failure Rate

Failures due to non-exempt splices, clamps, or connectors are not collected separately from all splices, clamps, or connectors.

Ignition Rate

Ignitions due to non-exempt splices, clamps, or connectors are not collected separately from all splices, clamps, or connectors.

Failure and Ignition Causes

Non-exempt connectors have designs that do not allow for expansion and contraction under different load scenarios. They also often clamp two conductors directly together and have threaded means of clamping. In these situations, a connection can appear to be tight, however it is difficult to determine if it became loose and became subjected to thermal expansion, which can result in arcing.

8.4.12.4 Non-Exempt Air Switches

Non-exempt air switches include grasshopper air switch and transmission air switch.

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☒	Substation ☐

Tracking ID: N/A

Condition Monitoring

Every line mile in HFTD and HFRA is inspected with the goal of seeking and identifying non-exempt equipment. An accurate inventory of non-exempt equipment is maintained. Grasshopper Air Switches inventory has been largely removed, and installed Grasshopper Air Switches are not operated.

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118 The supporting document is available at: PG&E's Community Wildfire Safety Program.

Maintenance Strategy

Preventative ☒	**Predictive ☐**	**Reliability-Centered ☐**	**Reactive ☐**
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

PG&E maintains a minimum firebreak of a 10-foot radius around both distribution and transmission poles with non-exempt equipment. See TD-7112S for maintenance of fire breaks and Guidance Document 015225 for equipment selection process.[119]

Replacement/Repair Condition

The Grasshopper Air Switches inventory has been largely removed, and installed Grasshopper Air Switches are not operated.

Timeframe for Remediation

PG&E does not operate Grasshopper Air Switches.

Failure Rate

PG&E does not operate Grasshopper Air Switches.

Ignition Rate

Ignitions due to non-exempt air switches are not collected separately from all air switches.

Failure and Ignition Causes

PG&E does not operate Grasshopper Air Switches.

8.4.13 Pre-GO 95 Legacy Equipment

Relevant Asset Types (Select all that apply)

Distribution ☐	**Transmission ☒**	**Substation ☐**

Tracking ID: N/A

[119] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

The PG&E transmission system includes conductor (Section 8.4.4), structures (Section 8.4.10), insulators (Section 8.4.14), and switches (Section 8.4.14) with install dates prior to 1941.

Condition Monitoring

PG&E inspects and maintains pre-GO 95 equipment to the same standards as other equipment. See Sections 8.4.4, 8.4.10, and 8.4.14 for condition monitoring applicable to pre-GO 95 equipment.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

PG&E inspects and maintains pre-GO 95 equipment to the same standards as other equipment. See Sections 8.4.4, 8.4.10, and 8.4.14 for maintenance strategy applicable to pre-GO 95 equipment.

Replacement/Repair Condition

PG&E inspects and maintains pre-GO 95 equipment to the same standards as other equipment. See Sections 8.4.4, 8.4.10, and 8.4.14 for replacement/repair conditions applicable to pre-GO 95 equipment.

Timeframe for Remediation

PG&E inspects and maintains pre-GO 95 equipment to the same standards as other equipment. See Sections 8.4.4, 8.4.10, and 8.4.14 for timeframe for remediation applicable to pre-GO 95 equipment.

Failure Rate

See Sections 8.4.4, 8.4.10, and 8.4.14 for failure rates that are inclusive of pre-GO 95 equipment.

Ignition Rate

See Sections 8.4.4, 8.4.10, and 8.4.14 for ignition rates that are inclusive of pre-GO 95 equipment.

Failure and Ignition Causes

Causal analysis for pre-GO 95 equipment is performed in the same manner as for other equipment. See Sections 8.4.4, 8.4.10, and 8.4.14 for failure and ignition causes applicable to pre-GO 95 equipment.

8.4.14 Other Equipment Not Listed

8.4.14.1 Transmission Line Switches

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☒	Substation ☐

Tracking ID: N/A

Condition Monitoring

Transmission switch maintenance is primarily identified through inspections and patrols including detailed, infrared, and switch function testing.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

Maintenance on switches is mainly driven by inspection findings, which are prioritized as described in Section 8.6. Typically, maintenance activities include repair, replacement, or removal. The maintenance activity is determined using TD-1001M, TD-8123P-103, job aids, and applicable standards.[120]

Timeframe for Remediation

The timeframe for remediation is defined in TD-8123P-103 and applicable job aids.

Failure Rate

The failure rate for transmission switches is provided in Table PG&E-8.4-1. Failure rate is calculated as HFTD or HFRA outages per HFTD or HFRA switch per year (switch count from 2024). Outages attributed to equipment failure, weather (except lightning), contamination, and unknown/other are included. Note that outages due to vegetation and third-party damage are not included.

[120] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

Ignition Rate

Ignitions for transmission assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1for tabulated ignition rates.

Failure and Ignition Causes

Asset-caused failures are assessed to determine level of causal evaluation needed. Both ignition and non-ignition events are included in processes documented through RISK-6306P-02 and TD-1050P-01.

Causes of the transmission switch ignitions fall into one category: Equipment – Failed. The causes of HFTD or HFRA transmission switch ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 100 percent.

8.4.14.2 Transmission Line Insulators

Relevant Asset Types (Select all that apply)

Distribution ☐	Transmission ☒	Substation ☐

Tracking ID: N/A

Condition Monitoring

Transmission insulator maintenance is primarily identified through inspections and patrols including detailed and infrared.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

Maintenance on insulators is mainly driven by inspection findings, which are prioritized as described in Section 8.6. Maintenance on insulators can occur during inspections or with input from an engineering assessment. Typically, maintenance activities include repair, replacement, or removal. The maintenance activity is determined using TD-1001M, TD-8123P-103, job aids, and applicable standards.[121]

Sampling and testing are expected from 2026 to 2028 to inform future maintenance requirements.

Timeframe for Remediation

The timeframe for remediation is defined in TD-8123P-103 and applicable job aids.

Failure Rate

The failure rate for transmission insulators is provided in Table PG&E-8.4-1. The failure rate calculation includes failures associated with insulator hardware, which is not generally tracked separately from insulator failures. Failure rate is calculated as HFTD or HFRA outages per HFTD or HFRA insulator set per year (generally one set of insulators per circuit on a structure, count from 2024). Outages attributed to equipment failure, weather (except lightning), contamination, and unknown/other are included. Note that outages due to vegetation and third-party damage are not included.

Ignition Rate

Ignitions for transmission assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

Asset-caused failures are assessed to determine level of causal evaluation needed. Both ignition and non-ignition events are included in processes documented through RISK-6306P-02 and TD-1050P-01.[122]

Causes of the transmission insulator ignitions fall into one of three categories: Equipment – Failed, Equipment – Overloaded, Contamination. The causes of HFTD or HFRA transmission switch ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 80 percent;

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121 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

122 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

- Equipment – Overloaded – 10 percent; and
- Contamination – 10 percent.

8.4.14.3 Other Equipment Not Listed

Relevant Asset Types (Select all that apply)

Distribution ☒	Transmission ☐	Substation ☐

Tracking ID: N/A

Condition Monitoring

“Other” category equipment maintenance is primarily identified through detailed overhead inspections and patrols. Detailed overhead inspections are both risk and compliance driven, performed as described in Section 8.3.

Maintenance Strategy

Preventative ☒	Predictive ☐	Reliability-Centered ☐	Reactive ☐
Targeted program in place for identification of conditions and addressing the condition before failure.	Targeted program in place to actively address risk before it is realized.	Targeted program in place to analyze assets and maintain critical asset functionality.	Replacement or repair of component after failure.

Replacement/Repair Condition

Typically, maintenance activities arising from inspection findings include repair, replacement, or removal.

Timeframe for Remediation

The timeframe for remediation of conditions arising from inspections is defined in TD-2305M[123] and applicable job aids.

Failure Rate

Failures for distribution assets were calculated as emergency (A) tags caused by equipment failure, pole rotten, unknown, or other with an associated unplanned outage. A-tags identified by inspection (or within three days of an inspection) were excluded as inspection finds, rather than true failures. A-tags caused by vegetation, third-party contact, etc. were excluded as non-equipment failures. Equipment types that are included in the other category in alphabetical order are: (1) Anchor, (2) Booster Regulator, (3) Crossarm, (4) Cutout, (5) Ground, (6) Guy, (7) Hardware/Framing,

[123] The supporting document is available at: PG&E’s Community Wildfire Safety Program.

(8) Insulators, (9) Jumper, (10) LAPP Insulator, (11) Molding, (12) Riser Pothead, (13) Switch, and (14) Tie Wire. The failure rate was calculated as the number of HFTD or HFRA failures on all equipment not listed in Table PG&E-8.4-1 divided by the number of known HFTD or HFRA structures in the system (structure count from 2024) per year.

Ignition Rate

Ignitions for distribution assets were calculated as the number of CPUC-reportable ignitions that were caused by equipment failure or overload and utility operation in HFTD or HFRA on overhead equipment. Ignitions with unknown causes and those caused by vegetation, second- or third-party contact, animal contact, vandalism, construction errors, or lightning were excluded. Ignitions caused by other distribution equipment include bonding wire, boosters, crossarms, cutouts, guy or span wires, insulators, jumpers, risers, switches, tie wires, and voltage regulators. The ignition rate was calculated as the number of HFTD or HFRA ignitions divided by the number of HFTD or HFRA failures per year. See Table PG&E-8.4-1 for tabulated ignition rates.

Failure and Ignition Causes

Cause of the failures fall into one of four categories: (a) equipment failure, (b) pole rotten, (c) other, and (d) unknown. The cause of HFTD or HFRA fuse failures from 2022-2024 are broken down as follows:

- Equipment Failed – 61 percent;
- Pole Rotten – 0 percent;
- Other – 17 percent; and
- Unknown – 23 percent.

Causes of the other distribution equipment ignitions fall into one of five categories: Equipment – Failed, Equipment – Overloaded, Utility Operation, Contamination, or Wire-Wire Contact. The causes of HFTD or HFRA other equipment ignitions from 2014-2024 are broken down as follows:

- Equipment – Failed – 81 percent;
- Equipment – Overloaded – 2 percent;
- Utility Operation – 3 percent;
- Contamination – 13 percent; and
- Wire-Wire Contact – 2 percent.

8.5 QA and QC

Tracking ID: GM-01D; GM-01T; GM-09D; GM-09T; GM-10D; GM-11D; GM-12D; GM-13D

8.5.1 Overview, Objectives, and Targets

In this section, the electrical corporation must provide an overview of each of its QA and QC activities for grid design, asset inspections and maintenance.[124] *This overview must include the following for each program:*

- *Initiative/activity being audited (each initiative/activity name must correspond to an initiative/activity described in Sections 8.2 – 8.4);*
- *Tracking ID from Table 8-1 or 8-2;*
- *Quality program type (QA or QC); and*
- *Objective of each QA and QC program.*

The electrical corporation must also provide the following tabular information for each QA and QC program:

- *Initiative/activity being audited (each initiative/activity name must correspond to an initiative/activity described in Sections 8.2 – 8.4);*
- *Type of audit (e.g., desktop or field);*
- *Population*[125]*/sample unit;*
- *Population size for each audited initiative/activity for each year of the 3-year WMP cycle;*
- *Sample size for each audited initiative/activity for each year of the 3-year WMP cycle;*
- *Percent of sample in the HFTD for each audited initiative/activity for each year of the 3-year WMP cycle;*
- *Confidence level and Margin of Error (MOE); and*
- *Target pass rate for each audited initiative/activity for each year of the 3-year WMP cycle.*

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[124] *Pub. Util. Code §§ 8386(c)(10), (22).*

[125] *In this section, a population may be the number of circuit miles inspected, the number of assets inspected, etc.*

PG&E defines elements of the quality management system in the following ways:

Quality Control (QC) is an independent function which assesses work outputs to verify alignment with specifications.

Quality Assurance (QA) is an independent function, which tests the output and design of work processes to provide guidance for continuous improvement on quality control methods and controls.

The QA/QC program has Targets IDs listed in Table 8-3. Tabular information describing the QA/QC program is listed in Table 8-4.

- Reporting: PG&E will use the targets in Table 8-3 and Table 8-4 below for quarterly compliance reporting including the QDR, QN, and the ARC. We note that throughout this 2026-2028 WMP, we discuss current plans for wildfire-related activities beyond the targets in Table 8-3. The timing and scope of these additional activities may change. We will not be reporting on these activities in our QDR, QN, or ARC because they are not defined targets but are descriptions of plans and activities in our 2026-2028 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All targets throughout this WMP are subject to External Factors. External Factors in this context are reasonable circumstances that may impact execution against targets including, but not limited to, physical conditions, environmental delays, landowner or customer refusals or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, wildfires, exceptions or exemptions to regulatory/statutory requirements, and other safety considerations.

- Utility Initiative Tracking IDs (Tracking IDs): We are including Tracking IDs in each section that has associated targets. Table 8-3 and Table 8-4 display the Tracking IDs we are implementing to tie the targets to the narratives in the WMP. The Tracking IDs will also be used for reporting in the QDR.

- High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Zone Areas: Unless stated otherwise, all initiatives described in Table 8-3 and Table 8-4 either involve work or audits on units or equipment located in, traversing, or energizing HFTD, HFRA, or Buffer Zone areas or involve units or equipment in HFTD, HFRA, or Buffer Zone areas.

TABLE 8-3:
GRID DESIGN, ASSET INSPECTIONS, AND MAINTENANCE QA AND QC PROGRAM OBJECTIVES

Initiative/Activity Being Audited	Tracking IDs of Initiatives Being Audited	Quality Program Type	Quality Management Initiative Tracking ID	Objective of the Quality Program
System Hardening – Undergrounding	GH-04	QC	GM-11D	Ensure that new construction meets applicable standards.
System Hardening – Undergrounding	GH-04	QA	GM-10D	Ensure that new construction meets applicable standards.
Open Tag Reduction – Distribution Backlog	GM-03	QC	GM-13D	Ensure that corrective repair work meets applicable standards.
Open Tag Reduction – Distribution Backlog	GM-03	QA	GM-12D	Ensure that corrective repair work meets applicable standards.
Aerial Scan Inspections - Distribution, Detailed Inspections – Distribution	AI-07A, AI-07D	QC	GM-09D[(a)]	Ensure inspections are following electrical corporation procedures for inspections.
Aerial Scan Inspections - Distribution, Detailed Inspections – Distribution	AI-07A, AI-07D	QA	GM-01D[(a)]	Ensure inspections are following electrical corporation procedures for inspections.
Detailed Inspection Transmission	AI-04	QC	GM-09T	Ensure inspections are following electrical corporation procedures for inspections.
Detailed Inspection Transmission	AI-04	QA	GM-01T	Ensure inspections are following electrical corporation procedures for inspections.

(a) GM-09D and GM-01D targets embed the Aerial Scan inspection program (AI-07A) with the Detailed Inspections – Distribution (AI-07D). The QA/QC will examine both AI-07A and AI-07D as a single population. The adjustments resulted from the Critical Issue RN-PGE-26-06. See 2026-2028 WMP Revision Notice Response R0 for additional information.

TABLE 8-4:
GRID DESIGN, ASSET INSPECTIONS, AND MAINTENANCE QA AND QC ACTIVITY TARGETS

Initiative/ Activity Being Audited	Quality Program Type	Type of Audit	Population/ Sample Unit	2026: Population Size	2026: Sample Size	2027: Population Size	2027: Sample Size	2028: Population Size	2028: Sample Size	Percent of Sample in the HFTD/HFRA	Confidence Level/Margin of Error (MOE)	2026: Pass Rate Target	2027: Pass Rate Target	2028: Pass Rate Target
System Hardening – Undergrounding	QC	Field/Desktop	Circuit Miles	360(a)	302(a)	307	264	400	329	100%	Minimum 99%/3%	80%	88%	95%
System Hardening – Undergrounding	QA	Field/Desktop	Circuit Miles	360(a)	187(a)	307	171	400	197	100%	95%/5%	88%	92%	95%
Open Tag Reduction – Distribution Backlog	QC	Field/Desktop	Distribution Overhead EC Tags	70,000(b)	25,000	70,000(b)	30,000	70,000(b)	35,000	100%	Minimum 99%/1%	80%	88%	95%
Open Tag Reduction – Distribution Backlog	QA	Field/Desktop	Distribution Overhead EC Tags	70,000(b)	383	70,000(b)	383	70,000(b)	383	100%	95%/5%	88%	92%	95%
Aerial Scan Inspections – Distribution, Detailed Inspections – Distribution	QC	Field/Desktop	Distribution Poles	350,000(c)	65,000	325,000(c)	65,000	235,000(c)	65,000	100%	Minimum 99%/1%	95%	95%	95%
Aerial Scan Inspections - Dist ribution, Detailed Inspections – Distribution	QA	Field/Desktop	Distribution Poles	350,000(c)	384	325,000(c)	384	235,000(c)	384	100%	95%/5%	95%	96%	97%
Detailed Inspection Transmission	QC	Field/Desktop	Transmission Structures	22,000	9,458	22,000	9,458	22,000	9,458	100%	Minimum 99%/1%	95%	95%	95%
Detailed Inspection Transmission	QA	Field/Desktop	Transmission Structures	22,000	378	22,000	378	22,000	378	100%	95%/5%	95%	96%	97%

(a) In response to Critical Issue RN-PGE-26-05, population size has been adjusted to reflect the updated workplan for 2026. Sample size has been updated accordingly. See 2026-2028 WMP Revision Notice Response R0 for additional information.

(b) Subject to change in alignment with Initiative/Activity Being Audited Workplan.

(c) In response to Critical Issue RN-PGE-26-06, population size has been adjusted to reflect the updated workplan for 2026-2028. QA/QC will example both Aerial Scan Inspections – Distribution (AI-07A) and Detailed Inspections – Distribution (AI-07D) as a single population. See 2026-2028 WMP Revision Notice Response R0 for additional information.

8.5.2 QA and QC Procedures

In this section, the electrical corporation must list the applicable procedure(s), including the version(s) and effective date(s), used for each grid design, operation, and maintenance QA and QC program listed in Table 8-3.

Guidance documents are subject to regular change; therefore, the revision numbers and effective dates below may not be applicable through the 2026-2028 WMP cycle. Please see Table PG&E 8.5.2-1 below for PG&E guidance document definitions.

TABLE PG&E-8.5.2-1:
QA/QC GUIDANCE DOCUMENTS

Initiative/Activity Being Audited	Quality Program Type	Applicable Procedures[(a)]	Version(s) and effective date(s)
System Hardening – Undergrounding	QC	RISK-6501P-01	10/2024, Rev: 0
System Hardening – Undergrounding	QA	RISK-6501P-01 RISK-6501S	10/2024, Rev: 00 10/2024, Rev: 00
Open Tag Reduction – Distribution Backlog	QC	RISK-6501P-05	04/2024, Rev: 4
Open Tag Reduction – Distribution Backlog	QA	RISK-6501S RISK-6501P-05	10/2024, Rev: 00 10/2024, Rev: 00
Aerial Scan Inspections – Distribution, Detailed Inspections – Distribution[(b)]	QC	RISK-6501P-04	04/2023, Rev: 0
Aerial Scan Inspections – Distribution, Detailed Inspections – Distribution[(b)]	QA	RISK-6501S RISK-6501P-08	10/2024, Rev: 00 10/2024, Rev: 00
Detailed Inspection Transmission	QC	RISK-6501P-04	04/2023, Rev: 0
Detailed Inspection Transmission	QA	RISK-6501S RISK-6501P-08	10/2024, Rev: 00 10/2024, Rev: 0

(a) The supporting documents are available at: PG&E's Community Wildfire Safety Program.
(b) Updated to include Aerial Scan Inspections in response to Critical Issue RN-PGE-26-06. See 2026-2028 WMP Revision Notice Response R0 for additional information.

8.5.3 Sampling Plan

In this section, the electrical corporation must describe how it determines the sample for each QA and QC program listed in Table 8-4. This must include how HFTD tier or other risk designations affect the sampling plan, and how the electrical corporation ensures samples are representative of the population.

To ensure samples are representative, random sampling is employed (simple random sampling or random sampling within strata). Please see Table PG&E-8.5.3-1 below for PG&E sampling plans definitions.

TABLE PG&E-8.5.3-1:
QA/QC SAMPLING PLAN

Initiative/Activity Being Audited	Tracking IDs of Initiatives Being Audited	Quality Program Type	Quality Management Initiative Tracking ID	Sampling Plan
System Hardening – Undergrounding	GH-04	QC	GM-11D	HFTD, HFRA, buffer areas, fire rebuild areas
System Hardening – Undergrounding	GH-04	QA	GM-10D	HFTD, HFRA, buffer areas, fire rebuild areas
Open Tag Reduction – Distribution Backlog	GM-03	QC	GM-13D	HFTD, HFRA, and buffer areas: priority informed by outage, ignition, Notice of Violation (NOV) trends
Open Tag Reduction – Distribution Backlog	GM-03	QA	GM-12D	HFTD, HFRA, and buffer areas: priority informed by outage, ignition, NOV trends
Aerial Scan Inspections – Distribution, Detailed Inspections – Distribution	AI-07A, AI-07D	QC	GM-09D[(a)]	HFTD, HFRA, and buffer areas: priority informed by extreme, severe, high-risk ranking. Not limited to any one inspection methodology and to include aerial scans.
Aerial Scan Inspections – Distribution, Detailed Inspections – Distribution	AI-07A, AI-07D	QA	GM-01D[(a)]	HFTD, HFRA, and buffer areas: priority informed by extreme, severe, high-risk ranking. Not limited to any one inspection methodology and to include aerial scans.
Detailed Inspection Transmission	AI-04	QC	GM-09T	HFTD, HFRA, and buffer areas: priority informed by extreme, severe, high-risk ranking
Detailed Inspection Transmission	AI-04	QA	GM-01T	HFTD, HFRA, and buffer areas: priority informed by extreme, severe, high-risk ranking

(a) GM-09D and GM-01D targets embed the Aerial Scan inspection program (AI-07A) with the Detailed Inspections – Distribution (AI-07D). The QA/QC will examine both AI-07A and AI-07D as a single population. The adjustments resulted from the Critical Issue RN-PGE-26-06. See 2026-2028 WMP Revision Notice Response R0 for additional information.

8.5.4 Pass Rate Calculation

In this section, the electrical corporation must describe how it calculates pass rates. This description must include:

- *The sample unit that generates the pass rate for each QA and QC program (e.g., for detailed distribution inspections, the sample unit that generates the pass rate may be a single inspection that passes or fails a QC audit); and*
- *The pass and failure criteria for each initiative/ activity listed in Table 8-3, including a discussion of any weighted contributions to the pass rate.*

Please see Table PG&E 8.5.4-1 below for our pass rate definitions.

**TABLE PG&E 8.5.4-1:
PASS RATE CALCULATION**

Initiative/ Activity Being Audited	Quality Program Type	Sample Unit	Pass Criteria	Fail Criteria	Pass Rate Calculation
System Hardening – Undergrounding	QC	Circuit Miles	Attributes meeting QC audit acceptance criteria	Attributes not meeting QC audit acceptance criteria	Passed opportunities/total opportunities
System Hardening – Undergrounding	QA	Circuit Miles	Attributes meeting QA audit acceptance criteria	Attributes not meeting all QA audit acceptance criteria	Passed opportunities/total opportunities
Open Tag Reduction – Distribution Backlog	QC	Distribution Overhead EC Tags	Passed opportunities within audit checklist acceptance criteria based on location attributes	Failed opportunities within audit checklist acceptance criteria based on location attributes	Passed opportunities over total opportunities.
Open Tag Reduction – Distribution Backlog	QA	Distribution Overhead EC Tags	Passed opportunities within audit checklist acceptance criteria based on location attributes	Failed opportunities within audit checklist acceptance criteria based on location attributes	Passed opportunities over total opportunities.
Aerial Scan Inspections – Distribution, Detailed Inspections – Distribution[(a)]	QC	Unique inspection reviewed	Unique count of inspections reviewed where Audit Findings = 0	Unique count of inspections reviewed where Audit Findings ≠ 0	Total inspections passed/Total inspections reviewed
Aerial Scan Inspections – Distribution, Detailed Inspections – Distribution[(a)]	QA	Unique inspection reviewed	Unique count of inspections reviewed where Audit Findings = 0	Unique count of inspections reviewed where Audit Findings ≠ 0	Total inspections passed/Total inspections reviewed
Detailed Inspection Transmission	QC	Unique inspection reviewed	Unique count of inspections reviewed where Audit Findings = 0	Unique count of inspections reviewed where Audit Findings ≠ 0	Total inspections passed/Total inspections reviewed
Detailed Inspection Transmission	QA	Unique inspection reviewed	Unique count of inspections reviewed where Audit Findings = 0	Unique count of inspections reviewed where Audit Findings ≠ 0	Total inspections passed/Total inspections reviewed

(a) Updated to include Aerial Scan Inspections in response to Critical Issue RN-PGE-26-06. See 2026-2028 WMP Revision Notice Response R0 for additional information.

8.5.5 Other Metrics

In this section, the electrical corporation must list metrics used by the electrical corporation to evaluate the effectiveness of its QA and QC programs and procedures (e.g., audit pass rates, outage rate within six months of inspection attributed to equipment condition or failure, new construction rework rate).

The Quality Management System considers overall pass rate, specific attribute pass rate, and geographical trend analysis provided in System Inspections Quality Management (QC & QA) programs reporting as the primary mechanism to both inform and evaluate the effectiveness of corrective actions resulting from quality audit activities. Over the 2022 to 2024 period System Inspections QC pass rates increased from 86.5 percent to 99.95 percent on Transmission assets and from 82.4 percent to 99.83 percent on Distribution assets. In the 2023-2024 period System Inspections QA pass rates increased from 99.95 percent to 99.97 percent on Transmission assets and from 92.88 percent to 99.69 percent on Distribution assets (QA of Systems Inspections was not in place prior to 2023).

8.5.6 Documentation of Findings

In this section, the electrical corporation must describe how it documents its QA and QC findings and incorporates lessons learned from those findings into corrective actions, trainings, and procedures. This must include a description of how the electrical corporation accounts for and documents the following when improving its inspections and maintenance QA and QC processes:

- *The number of inspections reviewed;*
- *The number of new issues identified;*
- *The number of repairs with a shortened deadline;*
- *The number of repairs with a longer deadline; and*
- *The number of recommended repairs cancelled.*

All QC and QA findings across programs are documented in Electric Operations Quality Management System of Record. Several dashboards aligned to PG&E's Lean methodology help PG&E review, analyze, and communicate the results of the audits with the relevant stakeholders. These reports include the number of reviews/audits performed as well as the number of new issues identified. There is not presently a quality management function to review repairs with shortened or extended timelines or cancelled recommended repairs, but development of a Notifications Quality Control mechanism is underway and planned to be deployed by 2027.

8.5.7 Changes to QA and QC Since Last WMP and Planned Improvements

In this section, the electrical corporation <u>must describe</u>:

- *A list of changes the electrical corporation made to its QA and QC procedure(s) since its last WMP submission;*
- *Justification for each of the changes including references to lessons learned as applicable; and*
- *A list of planned future improvements and/or updates to QA and QC procedure(s) including a timeline for implementation.*

Since the 2023-2025 WMP cycle, PG&E has expanded its QC coverage to include detailed ground, aerial, and climbing inspections for transmission and distribution assets. QC and QA programs for corrective repair work and new construction are also new additions to the WMP for the 2026-2028 cycle. We have also formalized procedures for each of these programs since the last WMP submission. These expanded and new scopes of quality management have been implemented as changes to the inspections process and have taken place with the intent of ensuring corrective repair work and new construction are performed to applicable standards. Notifications (repair tags) quality control is a notable area of quality management development and is planned to be deployed by 2027.

8.6 Work Orders

In this section, the electrical corporation must provide an overview of the procedures it uses to manage its open work orders resulting from inspections that prescribe asset management activities.[126] This overview must include a brief narrative that provides:

- *Reference to procedures documenting the work order process. The electrical corporation must provide a summary of these procedures or provide a copy in the supporting documents location on its website;*
- *A description of the plan for correcting any past due work orders (i.e., open work orders that have passed remediation deadlines), if applicable including the estimated date past due work orders in HFTD will be completed;*
- *A description of how work orders are prioritized based on risk;*
- *A description of procedures the electrical corporation uses for monitoring and/or reinspecting open work orders;*

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[126] *Pub. Util. Code §§ 8386(c)(10), (14).*

- *A discussion of how past trends of open work orders have informed the electrical corporation's current procedures and prioritization for addressing work orders. This must include analysis of the following:*
  - *Types of findings within the backlog;*
  - *Equipment types for the findings within the backlog;*
  - *Reinspection frequency for findings;*
  - *Outcomes of reinspection, including changes to prioritization or expected due dates; and*
  - *Prioritization level within the backlog.*[127]

In addition, each electrical corporation must provide an aging report for work orders past due[128] *(Table 8-5 and Table 8-6 provide examples).*

PG&E's definition of backlog as used below differs from that of Energy Safety. PG&E defines backlog as tags that are not past their compliance due date, but were open ignition EC notifications known as of January 5, 2023, and found prior to January 1, 2023, in HFTD/HFRA locations.

PG&E split Tables 8-5 and 8-6 into three tables to reflect separate work orders for transmission, distribution and substation. Table 8-5 was split into Table 8-5-1, Table 8-5-2, and Table 8-5-3 and Table 8-6 was split into Table 8-6-1, Table 8-6-2, and Table 8-6-3.

8.6.1 Transmission Tags

Tracking ID: N/A

Prioritization of open work orders (notifications) uses the priority levels A, E, and F that are defined in PG&E's procedure "Electric Transmission Line Guidance for Setting Priority Codes," TD-8123P-103 and correspond to GO 95 levels 1, 2, and 3, respectively. The B-priority for transmission notifications has been phased out as of the start of 2023 so that the internal priority levels have a one-to-one correspondence with the GO 95 levels. Priority E notifications now can be created with deadlines shorter than the allowable GO 95 timeframes and those with three-month deadlines are addressed in the same manner as the former priority B. A significant increase in the

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[127] *Electrical corporations must include the associated GO 95 Rule 18 level. If the electrical corporation uses a different prioritization level system, this must be included in addition to the GO 95 levels, with an explanation as to why the electrical corporation is using a different system.*

[128] *A past due work order is any work order that remains open beyond the shorter of two timeframes: the one required by the electrical corporation, or the one required by GO 95.*

number of notifications created since 2019 led to a backlog of E and F notifications requiring additional prioritization. However, the HFTD/HFRA ignition-related backlog of notifications created before 2023 has now been completed. HFTD or HFRA non-ignition-related notifications opened before 2023 will be repaired opportunistically through 2027, bundling the work with ignition-related notifications on the same structure or circuit when practical. New HFTD and HFRA notifications created in 2023 and later are targeted for repair by their required deadlines, barring external factors. There will continue to be a backlog of notifications in non-HFTD areas that are assessed through the Field Safety Reassessment (FSR) Program to monitor conditions for escalation if required.

Table 8-5-1 below shows the number of past due Transmission asset work orders categorized by age.

TABLE 8-5-1:
NUMBER OF PAST DUE ASSET WORK ORDERS CATEGORIZED BY AGE
(AS OF DECEMBER 31, 2024)

HTFD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
HFTD-Tier 2	33	88	149	934
HFTD-Tier 3	86	220	86	101
Zone 1	2	1	6	20
Non-HFTD HFRA	18	10	19	63
Non-HFTD Non-HFRA	191	1,727	2,709	8,018

Table 8-6-1 below shows the number of past due Transmission asset work orders categorized by priority level. Level 1 work orders completed in the field by December 31, 2024, and closed by clerical by January 31, 2025, were removed from the count due to the short turnaround times of these work orders.

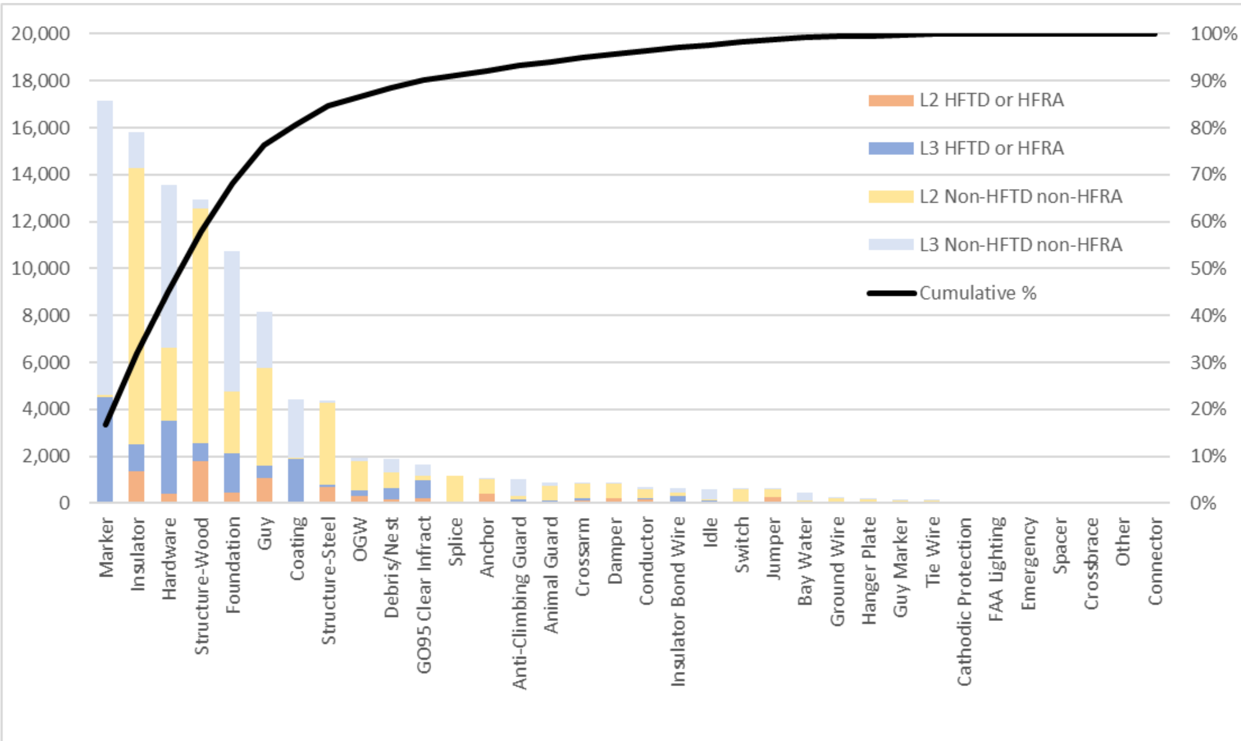
TABLE 8-6-1:
NUMBER OF PAST DUE ASSET WORK ORDERS CATEGORIZED BY PRIORITY LEVEL
(AS OF DECEMBER 31, 2024)

Priority Level	0-30 Days	31-90 Days	91-180 Days	181+ Days
Priority 1	–	–	–	–
Priority 2	296	1,959	2,795	8,763
Priority 3	34	87	174	373

Figure PG&E-8.6.1-1 below shows a Pareto chart of open notifications from Table 13 of the QDR, by type, with additional subdivisions for priority level, and HFTD or HFRA. Two of the most common notification types, Level 3 marker and foundation notifications, are expected to decrease following an upcoming review of notifications that potentially could be categorized as opportunity maintenance under GO 95, Rule 18(B)(1)(a)(iii).

Insulator notifications are another of the most common findings and have been the focus of standards changes related to grading rings and chipped bells.

FIGURE PG&E-8.6.1-1:
OPEN WORK ORDERS SYSTEM-WIDE AS OF DECEMBER 31, 2024
ELECTRIC TRANSMISSION



Requirements for reassessment of notifications are defined in PG&E's procedure "Transmission Line Corrective (LC) Notification Maintenance Strategy," TD-8123P-101.[129] Open notifications may be reassessed during a subsequent inspection of an asset. A FSR is scheduled for late notifications if the condition is capable of further degrading over time, and under some conditions this requirement may be satisfied by a reassessment occurring during an inspection. Notifications receive additional FSRs if they remain open, at an interval depending on the HFTD per TD-8123P-101.

Figure PG&E-8.6.1-2 shows the outcome of FSRs and other reassessments conducted during inspections for time-dependent notifications within the QDR population (all notifications found or completed since 2020, per Table 2), with the most recent reassessment evaluated in the same manner as for the QDR Table 13. Only notifications where the most recent reassessment occurred in the field, as opposed to desktop review after a standards change, are included.

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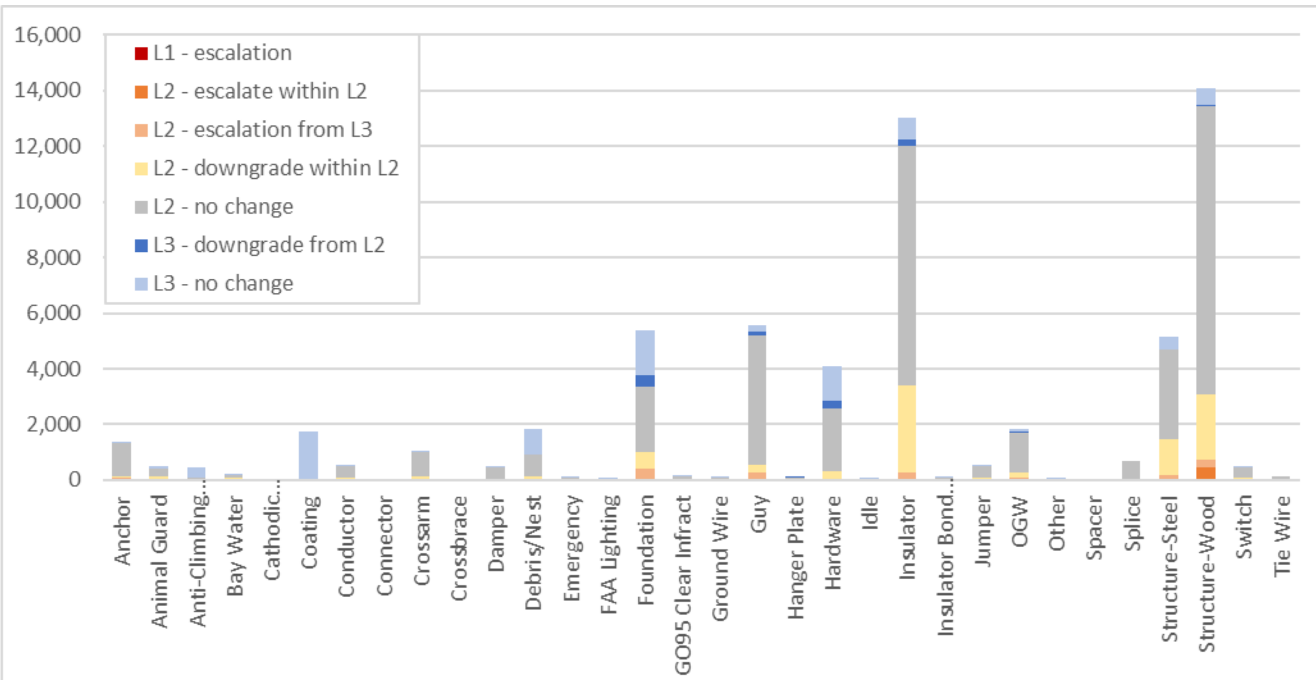
[129] The supporting document is available at: PG&E's Community Wildfire Safety Program.

Notifications are grouped by current level and escalations and downgrades from the original priority level. Since Level 2 notifications may have durations shorter than the maximum allowed under GO 95, Rule 18, escalations within Level 2 that shorten the deadline of the notification and downgrades within Level 2 that increase the deadline are shown separately. Escalations to higher priority levels or within Level 2 are relatively uncommon, less than 3 percent of reassessed notifications. Downgrades occurred primarily after PG&E re-aligned the maximum Level 2 duration in non-HFTD from the more conservative 1 year to the 3 years allowed under Rule 18.

FIGURE PG&E-8.6.1-2:
REASSESSMENT OUTCOMES FOR TIME-DEPENDENT NOTIFICATIONS



8.6.2 Distribution Tags

PG&E's definition of backlog for Distribution Tags as used below differs from that of Energy Safety. For Distribution, PG&E defines "backlog" as tags that were open ignition EC notifications known as of January 5, 2023, and found prior to January 1, 2023, in HFTD/HFRA locations.

Tracking ID: GM-03

Introduction

In 2019, PG&E began and completed the Wildfire Safety Inspection Program (WSIP) to proactively expand inspections of poles and associated equipment in HFTD/HFRA areas on an accelerated and enhanced basis to mitigate ignition risk. The WSIP inspections led to a significant increase in the volume of notifications.

At the end of 2024, we had approximately 200,000 notifications in our distribution HFRA/HFTD that were past due. Most of the outstanding tags are priority E and F tags. E and F tags represent conditions considered to have a moderate (E tag) or low (F tag) potential safety or reliability impact.

In 2024, we analyzed the population of open tags and improved our distribution inspection criteria to help our inspectors better identify conditions that lead to failure and/or present safety or reliability concerns. Based on engineering studies and a reassessment of failure modes, we developed more objective criteria tied to failure for use during inspections and tag creation. Our data show that the prior inspection criteria we developed in connection with WSIP identified many conditions that do not routinely lead to equipment failures. Ninety seven percent of equipment failures come from only eight equipment types: transformers, conductors, crossarms, poles, cutouts, jumpers, insulators, and connectors. Accordingly, we streamlined our inspection checklists to five questions to increase focus on identifying conditions on the assets that are the most likely to lead to failures. In addition, to assist our inspectors we updated the inspections job aid with significantly increased number of visual examples for potential asset failures.

In addition to updating inspection criteria to be better aligned with conditions that are indicative of failure, PG&E also transitioned to primarily using aerial inspections in HFTD in 2024 after several years of pilots. Aerial inspections allow PG&E to identify conditions that are challenging to see from the ground, such as pole top issues. The aerial program enables PG&E to identify with more certainty the conditions that are correlated to asset failure.

These changes to the distributions inspections program in 2024 have allowed PG&E to reduce the creation of ineffective tags that have lower risk.

In 2024 PG&E also started bundling EC notifications by isolation zone to maximize the number of notifications completed within a single outage and/or planned day of work. We prioritized by risk-spend-efficiency isolation zone bundling. Selecting the highest RSE isolation zones allow us to pick the tags that provide highest risk reduction per dollar spent.

Our bundled work plans are designed to improve reliability and lower costs. Through notification bundling, we can close more notifications per visit to each work location, which increases efficiency while reducing the impact to customers. Bundling also creates opportunities for financial savings as we close more notifications with fewer crew hours and resources. This can also lead to lower unit costs to complete the planned work.

Given our recent success with isolation zone bundling, we piloted a new mega-bundling program in 2024 to potentially obtain additional maintenance efficiencies. Mega bundling consists of treating an entire circuit as one project with a single scope of work. We then break projects into various smaller scopes (e.g., poles, tags, switches etc.). Concentration of work on a single project allows us to take a "one touch" approach to maintenance work for the benefit and safety of our customers and crews. Our goals for mega-bundling include: making field inspections and quality control more efficient, simplifying invoice processes, and reducing outages, execution and overhead costs. Given the success of our 2024 mega-bundling pilot, we are expanding the program in 2025. Our goal is to address over 16,000 EC notifications in the HFTD/HFRA through the program. This work will supplement the other isolation zone bundling work already included in our 2025 workplan.

Overall, in 2024, PG&E closed more than 95,000 distribution HFTD EC notifications, which is approximately 25,000 more notifications than we created in HFTD. In 2024, 53,000 of the closed EC notifications were backlog ignition risk notifications in the HFTD/HFRA. In 2023, we also closed 44,000 backlog[130] HFTD notifications. From 2023-2024, we closed more than 90,000 EC notifications that were backlog ignition risk notifications. This work eliminated over 73 percent of ignition risk from PG&E's maintenance notification HFTD backlog. We expect to remove more than 80 percent of the risk from the HFTD backlog by the end of 2025.

By bundling work based on isolation zones and circuits, PG&E has been able to eliminate more risk with a higher risk spend efficiency and lower impact to customers. The current volumetric target of executing a minimum of 25,000 more tags than created in the same year has also created execution challenges because of the uncertainty in the forecasted creations. The uncertainty in the forecast is driven by several factors, including the locations that are being inspected, changes to inspection criteria, and introduction of new inspection methods. Based on these learnings, PG&E is adjusting the GM-03 target to focus on increased volume of tag completion using a bundled workplan and to complete a higher volume of tags than created in preceding years instead of using in-year as the baseline.

The GM-03 targets shown below will allow PG&E to accelerate our bunding program and reach compliance by end of 2029 in a cost-effective manner. Bundling by isolation zone and circuit provides us the flexibility to address the most risk first through a risk spend efficiency (RSE) approach and will provide nearly $1 billion in execution efficiency through 2029 with equivalent risk reduction.

[130] Backlog for Distribution Tags is defined as the open ignition EC notifications known as of January 5, 2023, and found prior to Jan 1, 2023, in HFTD/HFRA locations.

The GM-03 commitment for the 2026-2028 WMP cycle contains two parts as follows:

First, during the period of 2026-2028, PG&E will cumulatively close a volume of tags equivalent to 160 percent of EC creations in HFTD/HFRA locations in the preceding three years (2025-2027). The yearly breakdown of the target is shown below.

- By the end of 2026, PG&E will close a volume of tags equivalent to 134 percent of the count of EC notifications created in HFTD/HFRA locations in 2025.
- By the end of 2027, PG&E will cumulatively close a volume of tags equivalent to 153 percent of the count of EC notifications created in HFTD/HFRA locations from 2025 and 2026.
- By the end of 2028, PG&E will cumulatively close a volume of tags equivalent to 160 percent of the count of EC notifications created in HFTD/HFRA locations from 2025 to 2027.

Cumulative closures, as used above for GM-03, are the total closures since 2026. Only creations and closures that have a compliance due date by end of 2029 count toward this commitment. The term "close" as used above means the closure of: (1) duplicate EC tags; (2) EC Tags where condition is confirmed to no longer exist; and (3) EC Tags where the compelling condition does not qualify as a tag based on the latest criteria defined in the inspection criteria standard, and/or qualifies as Opportunity Maintenance and is exempt from Rule 18 timelines.

Second, in each year, PG&E will close a number of tags that is equal to or greater than the number of tags created in HFTD/HFRA locations in the same year. This is to ensure that we are not further increasing the backlog.

Table PG&E-8.6.2-1 below shows the forecasted volume of tags created and closed each year.

TABLE PG&E-8.6.2-1:
ANNUAL FORECASTED CREATIONS AND CLOSURE VOLUME

Year	Forecasted Annual Created	Forecasted Cumulative Created Since 2025	Forecasted Annual Closures	Forecasted Cumulative Closures Since 2026	Total Closures EOY as a Percent of EC Tags Created Since 2025 to the Preceding Year
2025	76,000	76,000	N/A		
2026	59,000	135,000	102,000	102,000	134% (102,000/76,000)
2027	61,000	196,000	105,000	207,000	153% (207,000/135,000)
2028	N/A		107,000	314,000	160% (314,000/196,000)

In the narrative below, we describe how we prioritize work orders based on risk, explain our risk-informed plan for eliminating the backlog of open electric distribution EC tags in the HFTD/HFRA, and analyze our open work orders.

Reference to Procedures Documenting the Work Order Process

The procedures documenting PG&E's work order process can be found in two documents: (1) the Electric Distribution Maintenance Requirements (TD-2305S); and (2) the Electric Distribution Preventive Maintenance (EDPM) Manual (TD-8123M).[131]

Prioritizing Work Orders Based on Risk

PG&E uses a risk-informed prioritization approach to address the highest risk issues on our system. Maintenance tags generated through our inspection programs and routine activities are assigned a priority based on the potential safety impact.

Open work order (tags or notifications) prioritization uses priority levels A, B, X, E, F, and H as defined in the EDPM. Table PG&E-8.6.2-2 shows corrective action priorities and timelines as required by GO 95 Rule 18, PG&E's priority level, and PG&E's internal timeline for corrective actions (electric notifications).

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[131] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

TABLE PG&E-8.6.2-2:
ELECTRIC NOTIFICATIONS PRIORITY LEVELS

Line No.	GO 95 Rule 18	PG&E Priority	Description	GO 95 Rule 18 Timeline for Corrective Action	PG&E Internal Timeline for Corrective Action (Electric Notifications)
1	Level 1	A (Electric)	An immediate risk of high potential impact to safety or reliability.	Take corrective action immediately, either by fully repairing or by temporarily repairing and reclassifying to a lower priority.	Consistent with GO 95, Rule 18
2	Level 2	X (Electric Dx)	High potential impact to safety or reliability but do not pose an immediate risk (introduced in spring 2024).	Time period for corrective action to be determined at the time of identification by a qualified Company representative, but not to exceed: Six months for potential violations that create a fire risk located in Tier 3 of the HFTD. 12 months for potential violations that create a fire risk located in Tier 2 of the HFTD. 12 months for potential violations that compromise worker safety; and 36 months for all other Level 2 potential violations.	Corrective action within seven days from date condition identified for electric equipment
3		B (Electric Dx)	Any other risk of at least moderate potential impact to safety or reliability: Take corrective action within the specific time period (either by fully repairing or by temporarily repairing or reclassifying to Level 3 priority).	Same as above	Corrective action within 6 months from date condition identified for electric equipment

TABLE PG&E-8.6.2-2:
ELECTRIC NOTIFICATIONS PRIORITY LEVELS
(CONTINUED)

Line No.	GO 95 Rule 18	PG&E Priority	Description	GO 95 Rule 18 Timeline for Corrective Action	PG&E Internal Timeline for Corrective Action (Electric Notifications)
4		E (Electric)	Any other risk of at least moderate potential impact to safety or reliability: Take corrective action within the specific time period (either by fully repairing or by temporarily repairing or reclassifying to Level 3 priority).	Same as above	Corrective action within: Six months for conditions that create a fire risk located in HFTD Tier 3 12 months for conditions that create a fire risk located in HFTD Tier 2 Transmission: Corrective action timelines can be reduced below the maximum values listed above.
5		H (Electric Dx)	These are PG&E Priority "E" Notifications that are planned to be addressed by a planned System Hardening Project.	Same as above.	Same as above.
6	Level 3	F (Electric)	Any risk of low potential impact to safety or reliability.	Take corrective action within 60 months subject to the specific exceptions.	Corrective actions to be addressed within five years from date condition is identified.

Note: Exception – Potential violations specified in Appendix J or subsequently approved through Commission processes, including, but not limited to, a Tier 2 Advice Letter under GO 96B, that can be completed at a future time as opportunity-based maintenance. Where an exception has been granted, repair of a potential violation must be completed the next time the Company's crew is at the structure to perform tasks at the same or higher work level (i.e., public, communications, or electric level). The condition's record in the auditable maintenance program must indicate the relevant exception and the date of the corrective action.

Our highest priority is to complete all A, X, and B tags based on required compliance dates:

- Priority A tags require response by taking corrective action immediately, either by fully repairing or by temporarily repairing and reclassifying to a lower priority;
- Priority X tags are addressed within seven calendar days for asset conditions that pose a high potential impact to safety or reliability but do not pose an immediate risk; and
- Priority B tags are addressed within 6 months for potential violations that create risk of at least moderate potential impact to safety or reliability.

Figure PG&E-8.6.2-1 shows a Pareto chart of open notifications from Table 13 of the QDR, by type, with additional subdivisions for priority level, and HFTD or HFRA

FIGURE PG&E-8.6.2-1:
OPEN WORK ORDERS IN HFTD

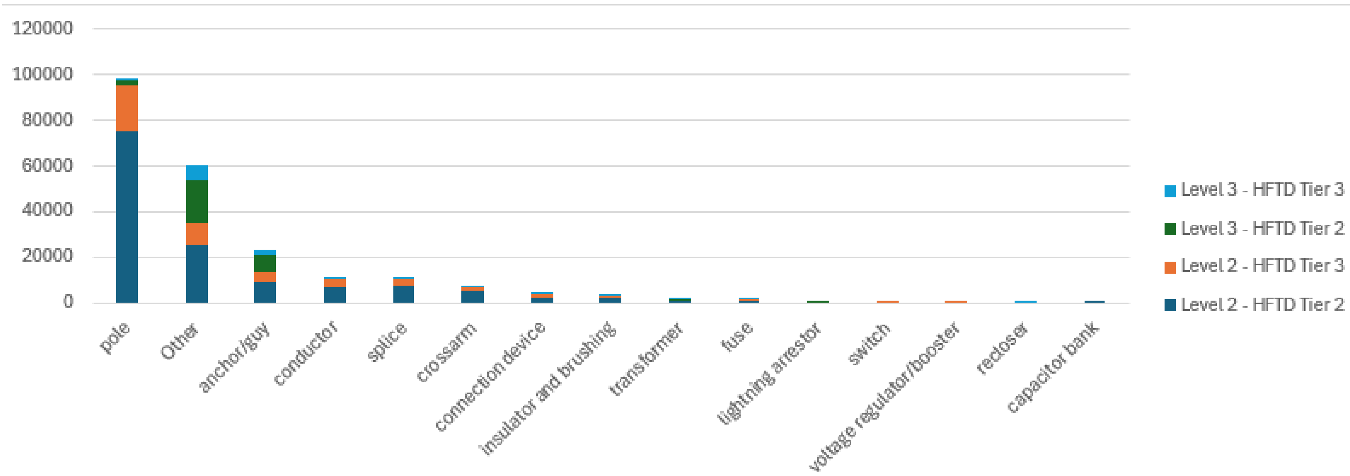

Table 8-5-2 below shows the number of past due Distribution asset work orders categorized by age.

TABLE 8-5-2:
NUMBER OF PAST DUE ASSET WORK ORDERS CATEGORIZED BY AGE AND HFTD TIER
(AS OF DECEMBER 31, 2024)

HFTD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
HFTD Tier 2	1	19	137	129,785
HFTD Tier 3	1	7	59	45,372

Table 8-6-2 below shows the number of past due Distribution asset work orders categorized by priority level.

TABLE 8-6-2:
NUMBER OF PAST DUE ASSET WORK ORDERS CATEGORIZED BY PRIORITY LEVEL
(AS OF DECEMBER 31, 2024)

Priority Level	0-30 Days	31-90 Days	91-180 Days	181+ Days
Level 2	2	26	196	167,295
Level 3	–	–	–	7,862

Notifications are reassessed per our Open EC Validation procedure outlined in TD-8123P-200.[132] Open notifications may also be reassessed during a subsequent inspection of an asset. When inspection teams encounter a Level 1 condition at an asset with an open Level 2 or Level 3 notification, a new Level 1 notification is written and the existing Level 2 or Level 3 notification is canceled. When inspection teams find a B tag condition on an asset with an open E tag, the E tag is escalated from priority E to priority B. The due date for the notification does not change because it remains a Level 2 finding.

8.6.3 Substation Tags

PG&E initiates corrective repairs and equipment replacements based on issues identified through maintenance and inspections of substations located in HFTD Tier 2, Tier 3, Zone 1 and HFRA. The corrective maintenance activity is intended to correct deficiencies so that substation equipment operates as designed and mitigates the risk of failure potentially leading to wildfire ignition.

Corrective work is prioritized and completed based on equipment condition and the risk of failure. Corrective work is tracked through Line Corrective (LC) notifications that are identified through inspections. The conditions and severities of each LC notification are evaluated individually using the Facility Damage Action (FDA) matrix to determine the needed mitigation and assigned a corresponding priority code. The priority codes (A, B, E, or F) specify the timeframe for mitigation and determine the due dates by which the LC notification should be completed. Substation LC priority codes and their associated timelines are documented in Substation Equipment Maintenance Requirements Standard (TD-3322S), and the FDA matrix process is documented in Substation SAP Work Management System (WMS) Process Procedure (TD-3320P-12).[133]

Substation LC notifications are targeted to be completed by their required end date (RED), if possible, and not to exceed the out of compliance (OOC) date. The current backlog of substation LC notifications were created in or after 2023. This population of

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[132] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

[133] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

LC notifications will be prioritized and scheduled in accordance with the timelines specified in Utility Standard TD-3322S and Utility Procedure TD-3320P-12, barring External Factors.

For all time dependent LC notifications that cannot be completed by the OOC date, a FSR or station inspection will be performed to evaluate the current condition of the corrective action. In addition, an FSR must be performed if a notification is determined to warrant a prioritization correction or reprioritization due to operational constraints or reasonable circumstances. The notification management prioritization correction and reprioritization process are documented in Substation SAP WMS procedure (TD-3320P-12).

Similarly, we perform corrective repairs and equipment replacements based on equipment condition and the risk of failure as described above. Power Generation corrective notifications are prioritized and processed as documented in Utility Standard PG-2498S and Utility Procedure for PG-2498P-01 for Hydro Generation. For Power Generation Fossil/Renewable facilities, the work management process is documented in Utility Procedure PG-4000P-04.[134] Identified issues result in corrective notifications that are assigned a repair priority code with specified due dates corresponding to the issue identified during the inspection.

Power Generation corrective notifications are targeted to be completed by their RED when possible. The current backlog of Power Generation corrective notifications was created in or after 2024 and will be prioritized and scheduled in accordance with the timelines specified in Utility Standard PG-2498S and Utility Procedures PG-2498P-01 and PG-4000P-04, barring External Factors. For all Power Generation notifications that cannot be completed by the required end date, a formal extension must be granted by appropriate authority as described in PG-2498P-01 and PG-4000P-04, depending on facility type, or a reassessment occurs during the next station inspection to evaluate the current condition of the corrective action.

Table 8-5-3 below shows the number of past due Substation LC notifications in HFTD/HFRA categorized by age. There are no past due Power Generation corrective notifications in HFTD/HFRA.

[134] The supporting documents are available at: PG&E’s Community Wildfire Safety Program.

TABLE 8-5-3:
NUMBER OF PAST DUE ASSET WORK ORDERS CATEGORIZED BY AGE
(AS OF DECEMBER 31, 2024)

HTFD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
Non-HFTD	32	13	34	6
HFTD-Tier 2	1	1	–	–
HFTD-Tier 3	–	–	–	–

Table 8-6-3 below shows the number of past due Substation asset work orders categorized by priority level.

TABLE 8-6-3:
NUMBER OF PAST DUE ASSET WORK ORDERS CATEGORIZED BY PRIORITY LEVEL
(AS OF DECEMBER 31, 2024)

Priority Level	0-30 Days	31-90 Days	91-180 Days	181+ Days
Level 1	–	–	–	–
Level 2	33	14	34	6
Level 3	–	–	–	–

8.7 Grid Operations and Procedures

8.7.1 Equipment Settings to Reduce Wildfire Risk

In this section, the electrical corporation must discuss the ways in which it operates its system to reduce wildfire risk.[135] *The equipment settings discussion must include the following:*

- *PEDS;*
- *Automatic recloser settings; and*
- *Settings of other emerging technologies (e.g., rapid earth fault current limiters).*

For each of the above, the electrical corporation must provide a narrative that includes the following, as applicable:

- *Settings used to reduce wildfire risk;*
- *Analysis of reliability/safety impacts for settings the electrical corporation uses. This must include the following:*
  - *Analysis of the most impacted circuits, including how the electrical corporation determined which circuits were most impacted;*
  - *The total number of outages that have occurred on the most impacted circuits when settings were enabled;*

The cumulative customer -minutes associated with outages on the most impacted circuits;

How the electrical corporation has worked to alleviate future reliability/safety impacts along the most impacted circuits;

- *De-energization protocols must consider impact on critical first responders, health and communication infrastructure, and medical baseline customers;*[136]
  - *The impacts via tabular data for the Top 10 most impacted circuits/circuit segments from the previous three years, as shown in* Table 8-7 *below:*
  - *Criteria for when the electrical corporation enables the settings;*
  - *Operational procedures for when the settings are enabled, including monitoring for re-energization;*

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[135] *Pub. Util. Code §§ 8386(c)(3), (6), (14).*

[136] *Pub. Util. Code §§ 8386(c)(6)(A), (B),(C).*

- *The number of circuit miles capable of these settings, including the percentage of circuit miles in the HFTD and HFRA covered by these settings;*
- *The percentage of time settings were enabled for the past three years based on the amount of times enablement criteria thresholds were met and led to activation, and the associated number of circuit miles encompassed by activation at that time; and*
- *An estimate of the effectiveness of the settings for reducing wildfire risk, including the calculation used for determining the effectiveness, a list of assumptions, and justification for these assumptions. The estimate must also include the number of ignitions that still occurred while sensitivity settings were enabled.*

8.7.1.1 Protective Equipment and Device Settings

Tracking ID: GM-07

Settings Used to Reduce Wildfire Risk

PG&E uses equipment settings to reduce wildfire risk. These include Enhanced Powerline Safety Settings (EPSS) and Downed Conductor Detection (DCD) capabilities on PG&E distribution lines, and EPSS on transmission lines. In addition to EPSS and DCD settings, other protective equipment and settings are leveraged to further reduce wildfire risk, including Sensitive Ground Fault (SGF), SmartMeter Partial Voltage (PV) Alert on distribution lines, and Communication Assisted Protection (ComAPS) on transmission lines, as described below.

EPSS is a protective measure that allows line protection devices, such as line reclosers, to address faults of varying magnitude and rapidly deenergize the line. These faults may occur due to a variety of reasons including, but not limited to vegetation striking a line, animal interference, third-party interference (e.g., a vehicle hitting a pole) or equipment failure. When EPSS is enabled on distribution and transmission line protective devices, power automatically turns off within one-tenth of a second if a fault is detected on the line that could result in an ignition.

Protective Equipment and Settings on Distribution Lines

Distribution circuits enabled with EPSS are configured to trip-bolted fault conditions at 100 milliseconds or less. EPSS settings also allow circuit breakers and reclosers to clear faults beyond fuses. This allows clearance of all fuse-protected circuit segments with ganged-three phase interruption to prevent back-feed into the fault.

Historically, the majority of ignitions that have occurred while EPSS protection is enabled have been the result of high impedance, low amperage fault conditions that were not detectable by traditional EPSS settings. DCD technology can improve the ability to detect and isolate high impedance faults before an ignition can occur. This technology and the algorithms associated with it are hardware vendor specific, but are commonly referred to as DCD for the purpose of this narrative. The engineering and programming of existing equipment capable of DCD and the installation of new equipment with DCD functionality helps to address high impedance fault conditions within the HFRA. To address fault types not yet fully mitigated through the EPSS Program, we began deployment of DCD in 2022 to supplement and provide enhanced ground fault protection to address low-current, high-impedance faults. Through 2024, DCD has been installed on 1,983 protection devices, providing enhanced protection across 87 percent of the HFTD/HFRA.

The GM-06 (DCD) commitment from the 2023-2025 WMP will conclude in 2025. DCD will continue as part of regular operational activities.

Additionally, when EPSS is enabled on three-wire distribution systems, SGF settings are implemented to help detect lower current fault conditions. This protection was generally set to identify 15 amperage faults within 15 seconds and de-energize the conductor to protect the line. In 2023, there were observed ignitions that occurred during EPSS protection that were lower than the detectable thresholds of DCD. It was identified that a lower SGF pickup could have interrupted the events sooner, potentially preventing the ignition (DCD not present). In 2024, we revised SGF trip floor settings criteria and device reprogramming planned for increased detection of high-impedance faults to 5 amperage faults within 5 seconds.

To further support our identification and response to high impedance faults, we have implemented new data-driven capabilities leveraging our SmartMeter network. PV Alerts work for the 3-wire distribution system with Line-to-Line connected transformers. PV Alert indicates low SmartMeter Voltage (25 – 75 percent of nominal 240V). Network Interface Card (NIC) remains on and able to return pings down to 25 percent Voltage, while metrology turns off at 75 percent voltage. New PV alert configuration settings prevent nuisance alerts from transient conditions. PG&E has also enabled single-phase and polyphase SmartMeter devices to send real-time alarms to the Distribution Management System when they detect partial voltage conditions.

A partial voltage condition is one where two or more SmartMeter devices indicate that the voltage passing through them has dropped, triggering an alarm at the Control Center. When wildfire conditions are elevated, the Control Center has the discretion to de-energize the circuit utilizing the existing SCADA capabilities. The partial voltage alarm indicates that there may be a low-current fault on the line. This capability helps PG&E detect and locate a downed wire within minutes, instead of relying on an employee assessment or customer alert. This can reduce the amount of time a downed line is energized and capable of potentially causing an ignition. A total of 86 partial voltage force outs were performed between 2022-2024, largely triggered by vegetation or animal contact.

Protective Equipment and Settings on Transmission Lines

Similar to distribution, transmission circuits enabled with EPSS are also configured to trip-bolted fault conditions at 100 milliseconds or less. There currently are two methodologies that can be utilized for fast tripping, EPSS or ComAPS.

EPSS on transmission assets involves setting protective relays with no intentional time delay. This is done by adjusting the setting at the source terminal of a radial Non-BES transmission line to ensure 100 percent of that protected line will have faults cleared with no time delay. This is accomplished by eliminating the time delay normally set for the purpose of relay coordination and may result in an unnecessary trip during a fault condition. Transmission EPSS is enabled and disabled on a seasonal basis.

Alternatively, ComAPS uses a communication channel(s) between two or more ends of a transmission line to provide no intentional time delay clearing over 100 percent of the line. It can be applied to both BES and Non-BES transmission lines, and both radial and networked lines, provided that the line has three terminals or fewer and each of the terminals has relays and a fault interrupting device, such as a circuit breaker. ComAPS is enabled year-round and is an industry-wide application traditionally deployed to ensure Protection System coordination and/or mitigate for system stability issues.

Analysis of Reliability/Safety Impacts for Settings the Electrical Corporation Uses

In 2024, we reduced the Customer Average Interruption Duration Index (CAIDI) and Customers Experiencing a Sustained Outage (CESO) for customers served by EPSS-capable lines as compared to data from the prior two-year average. Through the end of 2024, the average CAIDI was 150 minutes—a 17 percent reduction from the prior two-year average.

The average CESO through the end of 2024 was 818 customers—a 7 percent reduction from the prior two-year average of 880 customers. We focused on responding to all outages on EPSS-enabled circuits within 60 minutes. By the end of 2024, we responded to 93 percent of outages on EPSS-enabled lines within 60 minutes, responding on average within 36 minutes.

Furthermore, more than nine hundred thousand customers—52 percent of the customers protected by EPSS—experienced zero outages in 2024. However, on certain circuit segments, EPSS can exacerbate existing reliability issues. Approximately six percent of customers in scope for EPSS in 2024 experienced five or more outages while EPSS protection was enabled.

Additionally, EPSS protection has resulted in 629 potential wildfire saves through the end of 2024. The 629 saves include outages occurring due to equipment failure, vegetation contact, animal contact, or third-party contact, as well as DCD outages reviewed by our Engineering team and Gridscope identified outages, all with conditions historically precipitating in ignitions. Gridscope technology is a new and innovative solution that was implemented in 2023 to supplement existing wildfire mitigation strategies. Gridscope uses sensors and real-time monitoring to enhance grid reliability and safety, alongside other advanced technologies. Gridscope devices are state-of-the-art sensory devices that collect asset performance data that can be used in real-time to manage outages, as well as be used for work planning for future reliability programs. See Section 8.7.1.3.2 for more information on Gridscope.

We have conducted extensive analysis on the reliability impacts when EPSS is enabled, as well as highlighted the multiple actions we continue to take to reduce outage frequency and associated customer impact.

To enhance communication with customers who are experiencing outages, PG&E has developed a Foundry platform outage tool. The tool improves the visibility of impacted customers because it allows us to track outages at the customer level instead of at circuit or device level, which was the process in past years. It also provides outage cause (when available) and is used for the resilience program targeting of vulnerable customers. In 2024, we sent over 1.8 million text messages and over 200,000 e-mails to customers who experienced outages in EPSS-protected areas.

To further minimize outage impact, our Residential Storage Initiative (RSI) program offers a permanent battery installation for customers with Access & Functional Needs who are frequently impacted by EPSS outages. The permanent battery powers critical circuits within the home to provide backup power during these outages. In 2024, the RSI program installed 1,447 batteries for qualified customers and 1,890 batteries from inception through December 2024.

See ACI PG&E-25U-06 in Appendix D for more information about the EPSS Program's effort to enhance program reliability.

See Section 11.4 for more information on PG&E's public outreach and communications efforts related to first responders, health and communication infrastructure, and medical baseline customers.

Table 8-7 below shows our top 10 impacted circuits from changes to EPSS in the past three years.

TABLE 8-7:
TOP TEN IMPACTED CIRCUITS FROM CHANGES TO EPSS IN THE PAST THREE YEARS (2022-2024)

Circuit/Circuit Segment ID	Circuit/Circuit Segment Name	Circuit/Circuit Segment Length (Overhead Circuit Miles)	Number of Outages in Past Three Years	Cumulative Outage Duration (in Minutes)	Cumulative Number of Customers Impacted by Outages
183052113	Templeton 2113	321.7	59	13,622	75,974
083622106	Camp Evers 2106	79.9	52	17,961	60,189
043432104	Silverado 2104	142.2	52	23,246	39,419
253642101	Poso Mountain 2101	59.1	51	27,338	3,117
063172101	Madison 2101	168.1	51	16,476	27,571
182391103	Oilfields 1103	144.5	50	68,470	54,977
153662102	Apple Hill 2102	359.7	50	18,794	79,618
163351702	Curtis 1702	117.4	49	20,864	57,264
153082106	Placerville 2106	272.6	49	15,871	77,250
254061102	Dunlap 1102	55.3	46	28,294	4,934

Criteria for Enabling the Settings

The criteria for EPSS enablement are based on the Fire Potential Index (FPI). FPI ratings and their definitions are shown in Table PG&E-8.7.1.1-1 below.

TABLE PG&E 8.7.1.1-1:
WILDFIRE RISK LEVELS

Risk Level	Definition
R1	Very little or no fire danger.
R2	Moderate fire danger.
R3	Fire danger is so high that care must be taken using fire-starting equipment. Local conditions may limit the use of machinery and equipment to certain hours of the day.
R4	Fire danger is critical. Using equipment and open flames is limited to specific areas and times.
R5	Fire danger is so critical that using some equipment and open flames is not allowed in certain areas.
R5-Plus	The greatest level of fire danger where rapidly moving catastrophic wildfires are possible. This is typically when fire danger is R5 and there are additional high-risk weather triggers (e.g., strong winds).

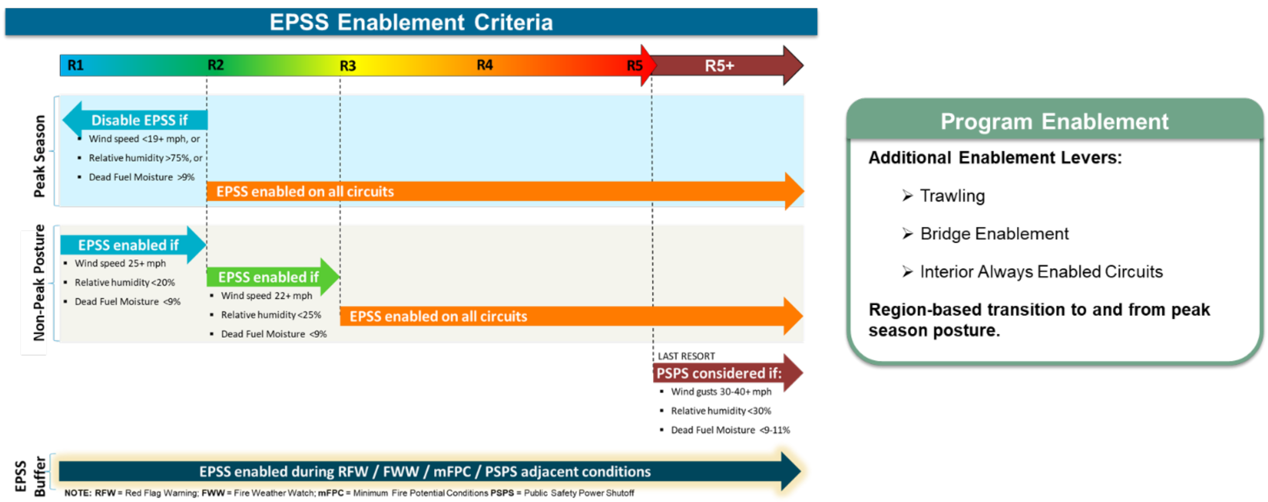
For the Distribution system, our current baseline Non-Peak Season criteria require EPSS enablement when an FPI rating of R3 is forecasted for at least an hour at the circuit level, or when a combination of high sustained wind speed, low relative humidity, and low 10-hour dead fuel moisture are present at R2 or R1.

When peak wildfire conditions are present—generally May to November—we will transition to our Peak Season criteria. The Peak Season criteria require EPSS enablement when an FPI rating of R2 is forecasted for at least an hour at the circuit level, or when a combination of forecasted high sustained wind speed, low relative humidity, and low 10-hour dead fuel moisture is present at R1.

We have engineered additional EPSS capability in HFRA adjacent areas, also referred to as EPSS buffer areas. Line miles in these areas are rarely EPSS enabled, with the exception of conditions like Red Flag Warnings (RFW) or Fire Weather Watches. Figure PG&E-8.7.1.1-1 below explains the conditions for EPSS enablement. See Section 10.6.1 for more information on how FPI is calculated and used in our operations.

Transmission enablement criteria differ from distribution enablement criteria due to the operational differences between PG&E's transmission and distribution systems and how these assets are controlled. Transmission assets are typically enabled for the duration of the season once a circuit is forecast to reach R3. The equipment is not transferred in or out of enablement like we do for the distribution system devices.

FIGURE PG&E-8.7.1.1-1:
FPI EPSS ENABLEMENT CRITERIA



We review multiple meteorological models daily that indicate—at the individual circuit level—which circuits are forecast to meet EPSS enablement criteria. This informs whether circuits need to be enabled for safety that day or can be disabled.

The criteria may be adjusted based on a regular review and analysis of evolving wildfire risk conditions and wildfire activity observed inside and outside of the service area.

At least twice a year, the PG&E Wildfire, Emergency and Operations (WEO) leadership team will participate in an Officer in Charge meeting with the Senior Vice President of WEO to determine the appropriateness of executing actions to go into peak wildfire season or returning systems to winter posture when wildfire risk is reduced. In making a decision to enter or exit peak wildfire season, the WEO team will review meteorological and fire science conditions, ignition trends, and the posture of State and Federal firefighting agencies. These meetings are designed to execute decisions including but not limited to the posture of EPSS in both Distribution and Transmission, as well as de-energization or re-energization of no-load circuit segments.

Operational Procedures for When the Settings Are Enabled, Including Monitoring for Re-Energization

For Distribution EPSS, we have established the EPSS and Patrol Process Procedure (TD-2700P-26).[137] This procedure outlines the patrol process when responding to outages on EPSS-enabled circuits. Generally, the process requires that the entire

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[137] The supporting document is available at: [PG&E's Community Wildfire Safety Program](#).

EPSS zone of protection—from the protection device that de-energized the line to the next protection device—must be patrolled for safety prior to re-energization.

This process is conducted by patrol teams unless the cause of the outage (e.g., a vehicle hitting a pole or a tree branch falling through the line) was previously identified. The process provides direction on how distribution operators and troubleshooters can use fault indicators and line sensors to help reduce the patrol footprint.

For Transmission EPSS, we have established the Transmission Line Switching, Non-Reclose, and EPSS Procedure (TD-1400P-07-Att02).[138] This procedure describes Electric Transmission Grid Control Center (GCC) wildfire operational mitigation activities for EPSS, disabling automatic reclosing, and the requirements for transmission line switching in any Tier 2/3 HFTD and HFRA. These wildfire operational mitigation activities, including patrols, are dependent on the utility FPI rating (R1, R2, R3, R4, R5, and R5-Plus).

If a transmission level outage occurs in HFRA or Tier 2/3 HFTD area, then patrolling is based on the ability to sectionalize and restore power to as many customers as possible. Patrol and restoring the transmission line, or section of line, is based on the FPI ratings.

The Number of Circuit Miles Capable of These Settings, Including the Percentage of Circuit Miles in the HFTD and HFRA Covered by These Settings

EPSS is capable on distribution lines in all HFRAs in our service territory and select adjacent EPSS buffer zones. PG&E may adjust the criteria for the EPSS buffer areas as stated above. Table PG&E-8.7.1.1-2 below summarizes the number and location of EPSS-capable miles through November 2024.

TABLE PG&E-8.7.1.1-2:
SUMMARY OF EPSS CAPABLE MILES

Mile Type	Miles	% Circuit Miles in HFRA
HFRA	25,026	100%
EPSS Buffer Zones	9,536	0%
Additional Miles (e.g., miles outside of HFRA or Buffer Areas electrically connected to an EPSS -capable device)	9,284	0%
Total	44,846	57%

[138] The supporting document is available at: PG&E's Community Wildfire Safety Program.

In total, 5,185 distribution line protection devices—which includes 3,802 in HFRA areas and 1,371 in EPSS buffer zones—were engineered to provide EPSS protection.

EPSS devices on another 61 transmission circuits were also engineered to provide EPSS protection.

The Percentage of Time Settings Were Enabled for the Past Three Years Based on the Amount of Times Enablement Criteria Thresholds Were Met and Led to Activation, and the Associated Number of Circuit Miles Encompassed by Activation at That Time

Over the last three years, PG&E has enabled 1,024 distribution circuits at different points in time depending on when each circuit met enablement criteria. The total potential circuit-days from 2022-2024 would then be 1,024 x 1,096 = 1,112,304. The number of circuit-days that EPSS has been enabled in the last three years is 326,283.

326,283/1,112,304 = 29.07% (Electric Distribution)

The associated number of circuit miles encompassed by activation is answered in the table above (Table PG&E-8.7.1.1-2); EPSS is scoped to protect 100 percent of HFRA miles whenever a circuit meets enablement criteria.

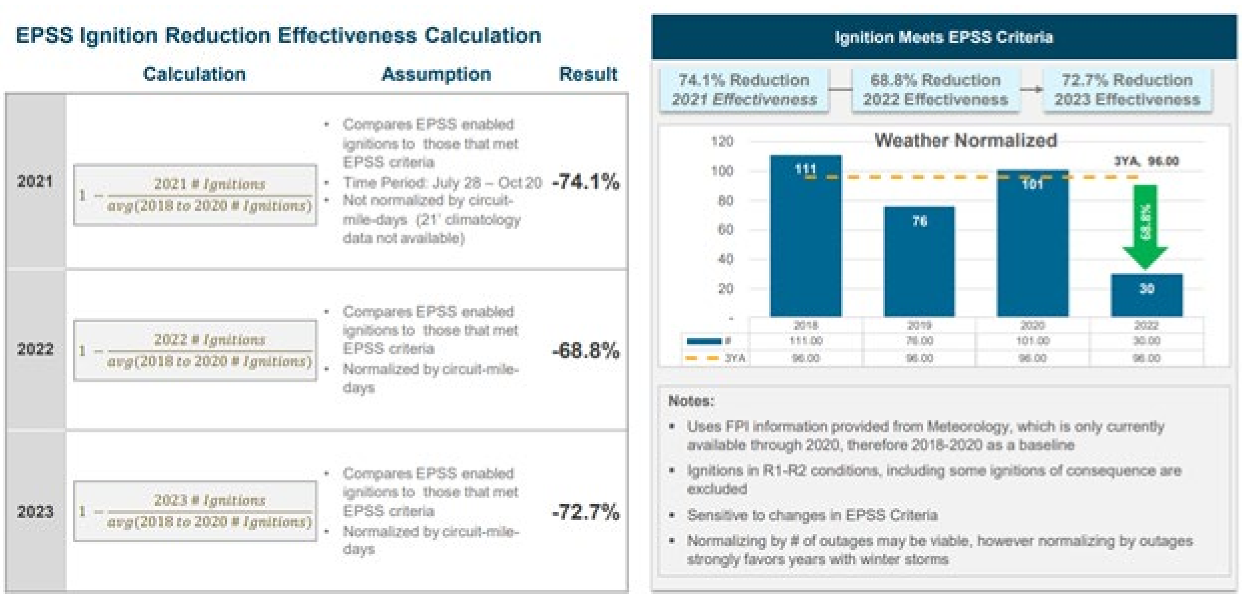
PG&E's strategy for transmission lines is more static for the season compared to distribution. The dates to go in and out of peak wildfire risk posture have been slightly different year-to-year; overall the transmission system was enabled for approximately 638 of the 1,096 days from 2022-2024, resulting in being enabled 58.2 percent of the time.

An Estimate of the Effectiveness of the Settings for Reducing Wildfire Risk Including the Calculation Used for Determining the Effectiveness, a List of Assumptions, and Justification for These Assumptions.

Using the formulas noted below, we saw respective effectiveness values of the program of 74.1 percent in 2021, 68.8 percent in 2022, and 72.7 percent in 2023.

Figure PG&E-8.7.1.1-2 below is our EPSS ignition reduction effectiveness calculation.

FIGURE PG&E-8.7.1.1-2:
EPSS IGNITION REDUCTION EFFECTIVENESS



In 2024, we moved to a Stratified Effectiveness methodology to understand EPSS effectiveness in reducing the rate of overall ignitions. This methodology systematically controls for exposure (both in the time and spatial dimension) by considering the circuit-mile day as the basic unit of analysis and comparing rates of ignitions under different EPSS conditions instead of counts. This has allowed us to measure the effectiveness of EPSS under conditions of elevated likelihood of destructive fire outcomes (R3) versus simply looking at the effectiveness of EPSS when enablement criteria is met. This can occasionally occur at FPIs lower than where we see destructive fire outcomes. With the new formula represented below, our current calculated effectiveness is 65.2 percent.

Figure PG&E-8.7.1.1-3 below provides our FPI-Stratified effectiveness calculation.

FIGURE PG&E-8.7.1.1-3:
FPI-STRATIFIED EFFECTIVENESS CALCULATION

"FPI-Stratified Effectiveness"

$$E = \left(1 - \frac{p_1}{p_2}\right) \times 100\%$$

Where $p_1 = \frac{\#\ ignitions\ with\ EPSS,\ by\ FPI}{circuit\text{–}mile\ days\ with\ EPSS,\ by\ FPI}$

and $p_2 = \frac{\#\ ignitions\ without\ EPSS,\ by\ FPI}{circuit\text{–}mile\ days\ without\ EPSS,\ by\ FPI}$

Since EPSS was expanded in 2022, it has helped significantly reduce overall Reportable Facility Ignitions in PG&E's service territory. Although EPSS has been more than 50 percent effective every year since 2022 in preventing ignitions, the following number of ignitions have occurred while EPSS protection was enabled.

- 2022 – 31 ignitions;
- 2023 – 22 ignitions; and
- 2024 – 47 ignitions.

All ignitions that occur during EPSS protection are reviewed by the EPSS Program Management Office, the PG&E Ignition Investigations team and engineers in our Distribution System Protection Program. These reviews have identified gaps that have informed further expansion of mitigation capabilities including DCD deployment and adjustments to SGF settings.

8.7.1.2 Automatic Recloser Settings

Settings Used to Reduce Wildfire Risk

Reclosing devices, such as circuit breakers and line reclosers, are designed to quickly and safely de-energize lines when a problem is detected and to minimize sustained outages by automatically re-energizing lines to restore service when momentary fault conditions occur. However, if the fault condition is not momentary, there is a risk of ignition from re-energizing a fault. Therefore, during peak wildfire risk the reclosing function is disabled for both transmission and distribution. In 2022, we aligned the disablement of automatic reclosing of protection devices with the enablement of EPSS on the distribution system.

Analysis of Reliability/Safety Impacts for Settings the Electrical Corporation Uses

We have conducted extensive analysis on the reliability impacts of the EPSS settings we use, which includes disablement of auto reclosing whenever EPSS is enabled. (See Section 8.7.1.1)

Criteria for When the Electrical Corporation Enables the Settings

Automatic reclosing can pose a risk of fire ignition during elevated fire conditions. When wildfire risk is elevated and circuits meet EPSS enablement criteria, EPSS is enabled on protection devices. At the same time, auto-reclosing is disabled on those devices until it is safe to return the device to normal protection settings.

On the distribution system, the criteria for enabling EPSS are described in Section 8.7.1.1. The same criteria apply to the disablement of auto-reclosing. On the transmission system, auto reclosing is disabled for the entire wildfire season when the FPI rating reaches R3 or greater.

Operational Procedures for When the Settings Are Enabled, Including Monitoring for Re-Energization

The operational procedures for disabling reclosers as a component of EPSS enablement are described in Section 8.7.1.1

The Number of Circuit Miles Capable of These Settings, Including the Percentage of Circuit Miles in the HFTD and HFRA Covered by These Settings

All EPSS-capable lines have automatic recloser settings. See Table PG&E-8.7.1.1-2 above for more information.

The Percentage of Time Settings Were Enabled for the Past Three Years Based on the Amount of Times Enablement Criteria Thresholds Were Met and Led to Activation, and the Associated Number of Circuit Miles Encompassed by Activation at That Time

Automatic reclosing is disabled whenever EPSS is enabled. See Section 8.7.1.1 for more information.

An Estimate of the Effectiveness of the Settings for Reducing Wildfire Risk Including the Calculation Used for Determining the Effectiveness, a List of Assumptions, and Justification for These Assumptions

The effectiveness of automatic recloser settings as a component of our EPSS Program is described in Section 8.7.1.1.

8.7.1.3 Settings of Other Emerging Technologies (e.g., Rapid Earth Fault Current Limiters)

8.7.1.3.1 Rapid Earth Fault Current Limiter

Settings Used to Reduce Wildfire Risk

A high impedance fault, like a downed wire or tree contacting a powerline, could remain undetected and become an ignition source. In addition, high impedance line-to-ground faults on distribution circuits are difficult to detect with traditional overcurrent protection devices. Rapid Earth Fault Current Limiter (REFCL) systems are intended to address these risks by detecting line-to-ground faults and limiting the fault current to below ignition thresholds.

Analysis of Reliability/Safety Impacts for Settings the Electrical Corporation Uses

As previously discussed in our response to ACI PG&E-23-07 of the 2025 WMP Update, the PG&E REFCL pilot at the Calistoga Substation continues to progress, but is still currently in the testing and evaluation stage. Reliability and safety impacts are being evaluated at the demonstration site. Field testing to date showed the technology limited ground fault currents to less than 1 amp. The reliability impact of REFCL with EPSS is being evaluated.

REFCL Has Been in-Service in Monitoring Mode, so Existing Line Protection Devices Operate for Sustained Faults. REFCL-Related Outages Have Only Occurred During Field Testing Activities. Criteria for When the Electrical Corporation Enables the Settings

REFCL is currently undergoing testing and evaluation as part of the pilot phase. The criteria for when the settings would potentially be enabled are being evaluated. Three different profiles for settings can be configured depending on field conditions.

Operational Procedures for When the Settings are Enabled, Including Monitoring for Re-Energization

The operational procedures for when the settings would potentially be enabled are being evaluated. When a ground fault occurs, the REFCL technology automatically determines if it is a sustained fault. If it is not a sustained fault, the system returns to normal with no service interruption. If it is a sustained fault, the fault is isolated in different ways depending on the active settings profile.

The Number of Circuit Miles Capable of These Settings, Including the Percentage of Circuit Miles in the HFTD and HFRA Covered by These Settings

We are in the process of evaluating an additional site for REFCL deployment. Staged fault testing at Calistoga was completed successfully in 2023, and REFCL was in-service off and on in 2024 in monitoring mode. REFCL protects the approximately 160 primary distribution circuit miles fed from the Calistoga Substation.

The Percentage of Time Settings Were Enabled for the Past Three Years Based on the Amount of Times Enablement Criteria Thresholds were Met and Led to Activation, and the Associated Number of Circuit Miles Encompassed by Activation at That Time

REFCL was cut-in 15 percent of the time in 2024 serving 160 circuit miles.

An Estimate of the Effectiveness of the Settings for Reducing Wildfire Risk Including the Calculation Used for Determining the Effectiveness, a List of Assumptions, and Justification for These Assumptions

The maximum sensitivity setting for REFCL at Calistoga is 1 Amp. This is based upon previous testing Energy Safe Victoria performed.

There have been no ignitions while REFCL has been in operation at Calistoga at the time of this filing.

REFCL has not been operational long enough to calculate effectiveness for reducing wildfire risk.

The combined ignition mitigation effectiveness of REFCL, CC overhead hardening, EPSS, and DCD has been evaluated as an alternative to undergrounding. For more information, see ACI PG&E-23-05.

8.7.1.3.2 Pole Mounted Sensor

Settings Used to Reduce Wildfire Risk

Through our EPSS Program, we are deploying Gridscope devices on our distribution system to provide enhanced situational awareness of outage locations to support both the initial patrol and restoration, as well as to provide data to inform secondary causal investigations on unknown outages. The technology is installed directly onto distribution poles and detects mechanical disturbances (i.e., vibrations, acoustics, infrared light, and visible light). Gridscope is not designed to operate as a distribution protection device the way a traditional circuit breaker, line recloser, or fuse would by detecting a fault and opening a circuit. However, through our initial rollout of the technology, we have found instances where Gridscope has detected a broken pole supporting energized conductors, as well as other hazards like vegetation leaning on energized powerlines, or animals that have contacted powerlines; all conditions that could have led to a potential ignition.

Gridscope began as a pilot of the EPSS Program in 2023, and we further expanded deployment of the devices in 2024. To date, over 10,080 devices have been installed on 37 circuits in 95 circuit protection zones in the HFRA.

Analysis of Reliability/Safety Impacts for Settings the Electrical Corporation Uses

The Gridscope pole mounted sensor is not designed to operate as a distribution protection device in the way a traditional circuit breaker, line recloser or fuse would by detecting a fault and opening a circuit. Therefore, there are no adverse reliability implications for implementing Gridscope.

There are positive reliability benefits for implementing Gridscope that PG&E has not yet fully quantified. For example, in our initial limited rollout of the technology we found ten instances where hazards were detected on energized conductors before any outage occurred. Additionally, we have had multiple instances where data from the devices was provided to troubleshooters prior to patrol and restoration activities began, allowing them to have more precise detail on the potential location, or in some cases actual location, of the fault activity, thereby significantly reducing the duration of the outage.

Examples of these successes with the Gridscope technology include a July 5, 2024, instance where a troubleshooter was provided a location from a Gridscope device where vegetation was found smoldering on an energized conductor. Once observed by the troubleshooter, the line was deenergized, preventing an ignition. In another instance on June 27, 2024, an outage on Placerville 2106, at a location that traditionally would generate an average CAIDI of 283 minutes, Gridscope data allowed troubleshooters to locate the specific fault location and reduce typical CAIDI by 70 percent to 88 minutes.

Criteria for When the Electrical Corporation Enables the Settings

The Gridscope pole-mounted sensor is not designed to operate as a distribution protection device in the way a traditional circuit breaker, line recloser, or fuse would by detecting a fault and opening a circuit. Therefore, it is not “enabled,” but rather, provides around-the-clock sensing of potential fault locations.

Operational Procedures for When the Settings Are Enabled, Including Monitoring for Re-Energization

Since Gridscope does operate as a protection device, there are no settings to be enabled, and thus, no operational procedures. The operational procedures are tied to the monitoring of the signals provided by the sensors.

The Number of Circuit Miles Capable of These Settings, Including the Percentage of Circuit Miles in the HFTD and HFRA Covered by These Settings

Gridscope sensors have been installed on approximately 900 circuit miles and approximately 3.5 percent of the circuit miles in the HFTD and HFRA benefit from having Gridscope sensors on poles. PG&E is evaluating scaling the technology across a larger number of circuits in the HFRA.

The Percentage of Time Settings Were Enabled for the Past Three Years Based on the Amount of Times Enablement Criteria Thresholds Were Met and Led to Activation, and the Associated Number of Circuit Miles Encompassed by Activation at That Time

The Gridscope pole mounted sensor is not “enabled,” but rather, provides around-the-clock sensing of potential fault locations.

An Estimate of the Effectiveness of the Settings for Reducing Wildfire Risk Including the Calculation Used for Determining the Effectiveness, a List of Assumptions, and Justification for These Assumptions

PG&E is currently undergoing testing to determine Gridscope effectiveness. There is no calculation available for estimating the effectiveness for reducing wildfire risk at this time.

8.7.1.3.3 Smart Tape

Smart Tape has been discontinued. For more information and lessons learned, see Section 13.3, Table PG&E-13-2: Lessons Learned from Discontinued Activities.

8.7.2 Grid Response Procedures and Notifications

The electrical corporation must provide a narrative on operational procedures it uses to respond to faults, ignitions, or other issues detected on its grid that may result in a wildfire including how the electrical corporation:

- *Locates the issues;*
- *Prioritizes the issues, including how operational models inform potential prioritization based on risk;*
- *Notifies relevant personnel and suppression resources to respond to issues; and*
- *Minimizes/optimizes response times to issues.*

In the following section, we describe our processes to identify faults on EPSS enabled circuits and to dispatch personnel to address them, as outlined in the EPSS – Electric Operations Restoration Dispatch Requirements Procedure (TD-2202P-01).[139]

Locates the Issues

PG&E's Emergency Operations Restoration Dispatch personnel monitor the Outage Information System/Outage Management Tool to ensure field personnel are dispatched quickly in response to EPSS outages. When an outage occurs on an EPSS enabled circuit, the outage will display a "Y" value in the EPSS column that indicates the outage is tied to EPSS protection.

Prioritizes the Issues, Including How Operational Models Inform Potential Prioritization Based on Risk

An EPSS outage is considered a priority as a potential ignition source given that EPSS is only enabled when the criteria of elevated wildfire risk is met. All EPSS outages are treated as potential ignitions and require emergency responses. PG&E targets to respond to all EPSS outages within 60 minutes to determine whether an ignition has occurred.

PG&E's restoration response and resource staffing plan is detailed below:

a) Standard Outage Response Protocols and Resource Escalation: PG&E's standard protocols for outage response include dispatch of trouble personnel resources from within the division where the outage has occurred. When local trouble personnel resources are exhausted, division leadership, in coordination with the Distribution Control Center Area of Responsibility, will assign local crew resources to support the patrol and restoration of the outage. If outage activity increases or durations are

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[139] The supporting document is available at: PG&E's Community Wildfire Safety Program.

extended, the division will look to general construction crews or neighboring divisions within the region to draw on available resources.

b) Storm Outage Prediction Program (SOPP) Model: A key resource to support local divisions in planning for daily resource requirements for anticipated outage activity is the Distribution System Operations SOPP. SOPP is a modeling system (a collection of models) that is used to predict the number of transformer level and above sustained outages per division for each of the next four days. The model combines wind, snow, and heat models into a single modeling system. The resource needs (crew and trouble personnel resources) are derived from the predicted storm outage numbers. For fair weather days, a historical background estimator has been developed to estimate the number of storm outages.

Notifies Relevant Personnel and Suppression Resources to Respond to the Issues

The EPSS – Electric Operations Restoration Dispatch Requirements Procedure (TD-2202P-01)[140] outlines a resource availability order that dispatch uses for deploying resources to respond to an EPSS outage. The initial response is to send a troubleshooter from the yard nearest the ignition. If a troubleshooter is unavailable, a Safety and Infrastructure Protection Team (SIPT) crew will respond if available. If neither a troubleshooter nor SIPT crew can respond within 60 minutes, then nine other employee groups can be contacted to quickly respond.

If the person(s) responding identifies an ignition, they will contact emergency services by calling 911 to report the ignition even if the fire has been suppressed. SIPT crews are wildfire mitigation teams that have been established to protect PG&E facilities in high-fire risk areas. Although SIPT crews have wildfire suppression capabilities, if they respond to an ignition, they will contact emergency services and coordinate any suppression activities with the Authority Having Jurisdiction and will follow guidelines established for private fire prevention resources.[141]

Minimizes/Optimizes Response Times to Issues

PG&E optimizes our response time to EPSS outages by targeting a response within 60 minutes using the closest available resources. This procedure also allows PG&E to visually confirm that an ignition has not occurred within the Circuit Protection Zone of the outage.

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140 The supporting document is available at: PG&E's Community Wildfire Safety Program.

141 See Assembly Bill (AB) 2380 (Reg. Sess. 2017-2018), Chapter 636. Available at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB2380. Available at: https://legiscan.com/CA/text/AB2380/id/1817969<https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB2380https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB2380.

8.7.3 Personnel Work Procedures and Training in Conditions of Elevated Fire Risk

The electrical corporation must provide a narrative on the following:

- *The electrical corporation's procedures that designate what type of work the electrical corporation allows (or does not allow) personnel to perform during operating conditions of different levels of wildfire risk, including:*
  - *What the electrical corporation allows (or does not allow) during each level of risk;*
  - *How the electrical corporation defines each level of wildfire risk;*
  - *How the electrical corporation trains its personnel on those procedures;*
  - *How it notifies personnel when conditions change, warranting implementation of those procedures; and*
- *The electrical corporation's procedures for deployment of firefighting staff and equipment (e.g., fire suppression engines, hoses, water tenders, etc.) to worksites for site-specific fire prevention and ignition mitigation during on-site work.*

PG&E's Preventing and Mitigating Fires While Performing PG&E Work Utility Standard EMER-4102S sets forth the requirements PG&E employees and our contract partners follow when traveling to work, performing work, or operating outdoors on or near any forest, brush, or grass covered land.

This standard includes a Wildfire Mitigation Matrix, which outlines the different types of work activities performed by PG&E employees and contractors along with required preventative measures that must be taken based on the daily fire danger. This includes a Wildfire Risk Assessment that crews use before beginning work to ensure all preventative measures within the matrix and standard are in place. (For a description of our risk level framework, see Table PG&E-8.7.1.1-1).

The Wildfire Mitigation Matrix also notes which work activities are not permitted in R5 and R5-plus conditions such as blasting, timber harvesting, construction hot work, heavy equipment use, and electric equipment repair or replacement. EMER-4102S is also consistent with all requirements included in the Public Resources Code (PRC).[142]

SAFE-1503 WBT (Fire Danger Precautions Training) is PG&E's fire danger safety training course. The course is designed to reduce the number of wildfires started by PG&E employees performing work in hazardous fire areas by educating them on how to take the proper precautions and implement fire mitigation measures. Per the EMER-4102S this course is required annually for all PG&E employees and contract

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[142] PRC, §§ 4421-4446.

partners performing PG&E work that may result in a spark, fire, or flame on or near any forest, brush, or grass-covered lands.

A PG&E Utility FPI Forecast e-mail is issued daily and contains the FPI ratings for that day and a forecast of the ratings for the next two days. Updates to RFWs and R5 plus rating values are released midday via e-mail when applicable.

Utility Standard – EMER-4102S identifies when to deploy firefighting staff and equipment based on the daily FPI. Utility-caused ignitions pose a risk to the environment, the utility system, work personnel, and the public. Utility Standard – EMER-4102S establishes procedures for mitigating fire danger and the consequences of an accidental ignition. The standard includes work activity guidelines that set forth the type of work that can be performed during different levels of wildfire risk.

PG&E also implements our SIPT Program that supports resources performing work in HFRAs. SIPT crews consist of two to three represented employees from the International Brotherhood of Electrical Workers who are trained and certified as SIPT personnel. The SIPT crews provide standby resources for PG&E crews performing work in high fire hazard areas, pre-treatment of PG&E assets during any ongoing fire, fire protection to PG&E assets, and emergency medical services. SIPT crews perform high priority fire mitigation work, protect PG&E assets, and gather critical data to help prepare for and manage wildfire risk. SIPT crews perform both routine and emergency work.

8.8 Workforce Planning

In this section, the electrical corporation must provide an overview of personnel, including qualifications, and training practices, related to workers in roles associated with asset inspections, grid hardening, and risk event inspection.[143]

8.8.1 Asset Inspections

Tracking ID: GM-15

Overview

Asset Inspections are assigned to either contract or internal qualified personnel who have received the training to be classified as Qualified Company Representative (QCR) Inspectors focused on Distribution Inspections, which supports wildfire mitigation.

Table PG&E-8-9 below provides:

- A list of all worker titles relevant to a target role; and
- The minimum qualifications for each of those titles.

To improve the qualifications of asset inspectors, PG&E performs annual reviews of the System Inspection training program and incorporates approved changes from Standards and Asset Strategy teams. The training program incorporates updates and changes to the Inspect Application tool so that inspectors are well qualified to document and prioritize corrective actions. The training program review for QCR workers is represented by GM-15 in Section 8.1.

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[143] *Pub. Util. Code §§ 8386(c)(16), (19).*

TABLE PG&E-8-9:
WORKFORCE PLANNING, ASSET INSPECTIONS

QCR Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements	Reference to Electrical Corporation Training/Qualification Programs
Compliance Inspector	QEW Consisting of Journeyman Lineman and New Inspector Training	Compliance Inspector Training Course	ELEC-1000 (Initial) TECH-0020 (Refresher) ELEC-0340 (CONT) ELEC-0341 (CONT) ELEC-0342 (CONT)
Compliance Inspector – Underground	Journey Level Cable Splicer	Compliance Inspector Training Course	ELEC-1000 (Initial) TECH-0020 (Refresher) ELEC-0340 (CONT) ELEC-0341 (CONT) ELEC-0342 (CONT)

(a) All PG&E employees and contractors meet the minimum qualifications for the assigned role.

8.8.2 Grid Hardening

Overview

Grid hardening projects, including undergrounding, are generally assigned to internal crews or contractors for the duration of the project's construction. Table PG&E 8-10 below includes an overview of personnel, qualifications, and training for both contracted and internally resourced grid hardening projects.

Qualifications and Training Practices

The lineman and foreman roles for grid hardening projects are filled by Qualified Electric Workers (QEW). To perform grid hardening work, at least one worker on-site must be a QEW. In some instances, work can be performed by workers who lack QEW status as long as the work is performed under the direction of a QEW.

To become a QEW, a worker must pass a PG&E-certified journeyman apprenticeship program, called the Apprenticeship Line Program (ALP). The ALP is a four year apprentice program that requires written, hands-on technical, and physical tests, and provides on-the-job training. Field training coordinators monitor the successful progression of apprentice lineman to journeyman lineman.

PG&E also trains all general construction coworkers in fire ignition safety for when they work on our facilities. Workers are trained to identify any safety issues such as outdated hardware among other issues, how to write an EC tag if any safety issues are identified, and how to review fire index ratings prior to working in a specific area.

Table PG&E 8-10 below summarizes the minimum qualifications for workers assigned to grid hardening projects.

TABLE PG&E-8-10:
WORKFORCE PLANNING, GRID HARDENING

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements/ Qualifications	Reference to Electrical Corporation Training/ Qualification Programs
General Foreman (Ext. only)	18 years of age or older High School Diploma, GED or equivalent experience Journeyman Lineman having completed an accredited apprenticeship program International Brotherhood of Electrical Workers (IBEW) Journeyman Lineman status in good standing Class A California driver's license	QEW Journeyman Lineman Certificate (union sponsored) (i.e., NECA, IBEW Seal and Apprentice Certification)	Electrical Corporation: Required Trainings relevant to Wildfire Mitigation (see paragraphs above) Contractor: Contractor company is responsible for the qualifications of their employees. However, contracted employees are held to the same standards as PG&E employees. Multiple PG&E departments perform safety observations of contractors and perform quality audits of completed work. Contractors should have ISN badges that are confirmed by Environmental Health and Safety org. during site visits.
Foreman (Elec. Corporation PG&E and External)	18 years of age or older High School Diploma, GED or equivalent experience Journeyman Lineman having completed an accredited apprenticeship program IBEW Journeyman Lineman status in good standing Class A California driver's license	QEW Journeyman Lineman Certificate (union sponsored) (i.e., NECA, IBEW Seal and Apprentice Certification)	See above

TABLE PG&E-8-10:
WORKFORCE PLANNING, GRID HARDENING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements/ Qualifications	Reference to Electrical Corporation Training/ Qualification Programs
Lineman	18 years of age or older	QEW	See above

TABLE PG&E-8-10:
WORKFORCE PLANNING, GRID HARDENING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements/ Qualifications	Reference to Electrical Corporation Training/ Qualification Programs
(Elec. Corporation PG&E and External)	High School Diploma, GED or equivalent experience Journeyman Lineman having completed an accredited apprenticeship program IBEW Journeyman Lineman status in good standing Class A California driver's license	Journeyman Lineman Certificate (union sponsored) (i.e., NECA, IBEW Seal and Apprentice Certification)	
Apprentice Lineman	18 years of age or older High School Diploma or GED Successful passing of the ALP and the Three-Day Climbing Couse Valid California driver's license Valid Class A California driver's permit and DMV medical card within 3 months of hire Valid Class A California driver's license and DMV medical card within 6 months of hire Various physical requirements	N/A	See above
Groundman (Ext. only)	18 years of age or older Class A California driver's license with tanker endorsement	Occupational Safety and Health Administration (OSHA) 10	See above
Utility Worker (Electrical Corp. only)	18 years of age or older High School Diploma or GED Valid CA Class C driver's license (or higher) Valid CA Class A license within three months of hire Various physical requirements	N/A	See above
Misc. Equipment Operator (Electrical Corp. only)	18 years of age or older High school diploma or GED Valid CA Class A driver's license permit Valid DMV Medical Card Various physical requirements	N/A	See above
Cable Splicers	18 years of age or older	IBEW journeyman card for Cable Splicer or State JATC certification	See above

TABLE PG&E-8-10:
WORKFORCE PLANNING, GRID HARDENING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements/ Qualifications	Reference to Electrical Corporation Training/ Qualification Programs
	High School Diploma or GED Valid CA Class C driver's license (or higher) 2 years' experience as Journey Cable Splicer	40-hour Switchman Training Certification / Card	
Apprentice Cable Splicer	Valid Class C California driver's license	N/A	See above
Electric Crew Inspector (External)	Journeyman Lineman or certified by duly constituted Outside Line Construction Local Union of the IBEW with at least 3.5 years in the trade. Valid Class C California driver's license.	Journeyman Lineman Certificate	See above
Civil Crew Inspector	Valid Class C California driver's license.	OSHA 10	See above

(a) All PG&E and contract employees must meet the minimum qualifications for performing the assigned role.

8.8.3 Risk Event Inspection

Overview

Risk Event Inspections are typically assigned to internal crews who perform programming, testing, troubleshooting, switching, maintenance, and inspections of electric field equipment during routine cycles and event responses. Table PG&E-8-11 includes information on the qualifications and training requirements for personnel who may perform Risk Event Inspections.

Qualifications and Training Practices

Table PG&E-8-11 includes information on the qualifications and training requirements for personnel who may perform Risk Event Inspections.

TABLE PG&E-8-11:
WORKFORCE PLANNING, RISK EVENT INSPECTION

Worker Title	Minimum Qualifications for Target Role	Special Certification Requirements	Reference to Electrical Corporation Training/Qualification Programs
Troublemen	QEW. In some instances, work can be performed by non -QEWs roles, but the work is always performed under the direction of a QEW.	N/A – Nothing beyond QEW	While these roles do not have certifications directly related to Wildfire and PSPS mitigation, these roles and their work is important to the ongoing, safe operation of PG&E equipment throughout our Service Area, including to mitigate wildfire risks.
Distribution Line Technicians	QEW. In some instances, work can be performed by non -QEWs roles, but the work is always performed under the direction of a QEW.	N/A – Nothing beyond QEW	There is a specialized training program to inspect and maintain critical line control and voltage devices. While these roles do not have certifications directly related to Wildfire and PSPS mitigation, these roles and their work is important to the ongoing, safe operation of PG&E equipment throughout our Service Area, including to mitigate wildfire risks.

(a) All PG&E employees meet the minimum qualifications for performing the assigned role.
(b) PG&E does not use contractor resources for these roles. This work is completed by PG&E employees.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 9

VEGETATION MANAGEMENT AND INSPECTIONS

9. Vegetation Management and Inspections

Each electrical corporation's Wildfire Mitigation Plan (WMP) must include plans for vegetation management.[144]

Pacific Gas and Electric Company's (PG&E) Vegetation Management (VM) organization supports customers and communities by managing vegetation located near powerlines, to mitigate wildfire and reliability risks.

VM continues to evolve its operating model through risk-informed planning and execution of a portfolio of programs. Building upon lessons learned, PG&E plans to streamline its inspection programs, while targeting high risk areas of the system to continuously reduce the risk of ignitions associated with vegetation-caused interruptions. PG&E plans to adjust the Distribution Routine Patrol Program in 2026-2028 by consolidating inspection procedures and exploring the use of technology to support inspections. Adjustments to the program reflect efforts to improve customer sentiment (i.e., reducing customer touchpoints) and feedback from external stakeholders (i.e., areas of continuous improvement). Each update is described in the bullets below.

For the 2026-2028 period, PG&E's VM organization will focus on:

- Consolidating VM Distribution inspection programs;
- Leveraging technology to inform and/or supplement planning, execution, or verification of work performed;
- Utilizing and evolving operational analytics to enable risk-informed work execution; and
- Improving VM critical data sets.

Additional detail on these strategies is provided below. See also Section 12.1.1, Tracking ID ES-01, for additional information regarding data quality remediation for critical VM data sets.

9.1 Targets

In this section, the electrical corporation must provide qualitative and quantitative targets for vegetation management and inspections for each year of the 3-year WMP cycle.[145] *The electrical corporation must provide at least one qualitative or quantitative target for the following initiatives:*

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[144] *Pub. Util. Code §§ 8386(c)(3), (9).*

[145] *All end-of-year (EOY) targets in all sections of the WMP must follow the calendar year.*

- *Wood and Slash Management (Section 9.5);*
- *Defensible Space (Section 9.6);*
- *Integrated Vegetation Management (Section 9.7); and*
- *Workforce Planning (Section 9.13).*

Quantitative targets are required for vegetation management inspections and pole clearing; see Section 9.1.2, below, for detailed requirements.

Quantitative targets are required for Quality Assurance (QA) and Quality Control (QC). See Section 9.11.1 for detailed quantitative target requirements for QA and QC. Reporting of QA and QC quantitative targets is only required in Section 9.11.

VM Qualitative and Quantitative targets by year are summarized in Table 9-1 and Table 9-2 below. Additional detail is provided in the section(s) and page number(s) indicated.

- Reporting: PG&E will use the targets in Table 9-1 and Table 9-2 below for quarterly compliance reporting including the: Quarterly Data Report (QDR), Quarterly Notification (QN), and the Annual Report on Compliance (ARC). Throughout this 2026-2028 WMP, we discuss current plans for wildfire-related activities beyond the targets in Tables 9-1 and 9-2 below. The timing and scope of these additional activities may change. We will not be reporting on these activities in our QDR, QN, or ARC because they are not defined targets, but are described in our 2026-2028 WMP to provide a complete picture of our wildfire mitigation activities.
- External Factors: All targets throughout this WMP are subject to External Factors. External Factors in this context are reasonable circumstances that may impact execution against targets, including, but not limited to, physical conditions, environmental delays, landowner or customer refusals or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, wildfires, exceptions or exemptions to regulatory/statutory requirements, and other safety considerations.
- Utility Initiative Tracking IDs (Tracking IDs): We are including Tracking IDs in each section that has associated targets. Table 9-1 and Table 9-2 include the Tracking IDs we are implementing to tie the targets to the narratives in the WMP. The Tracking IDs will also be used for reporting in the QDR.
- % Risk Impact: The "% Risk Impact" is calculated based on the risk reduction of the mitigation initiative divided by total overall utility risk. The "% Risk Impact" provided is an estimate based on the best available workplans applied against the latest risk models as of the time of this filing. In many cases, the workplans contain units exceeding the target presented to ensure target completion is feasible. We anticipate that as mitigation work takes place and as risk models and workplans are updated, the estimated "% Risk Impact" projections could change. Additionally, because inspections do not reduce risk in isolation, for inspection and

line-sensor-related targets we include an “eyes-on-risk” value to provide insights into the level of risk being assessed.

- High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Zone Areas: Unless stated otherwise, all initiatives described in Table 9-1 and Table 9-2 either involve work or audits on units or equipment located in, traversing, or energizing HFTD, HFRA, or Buffer Zone areas.

9.1.1 Qualitative Targets

The electrical corporation must provide qualitative targets for implementing and improving its vegetation management and inspections,[146] *including the following:*

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs (“Previous Tracking ID”), if applicable;*
- *A completion date for when the electrical corporation will achieve the qualitative target; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated.*

Qualitative targets for vegetation management programs are summarized in Table 9-1 below. Additional detail is provided in the section(s) and page number(s) indicated.

[146] *Annual information included in this section must align with the applicable data submission.*

TABLE 9-1:
VEGETATION MANAGEMENT TARGETS BY YEAR (NON-INSPECTION TARGETS)

Initiative	Quantitative or Qualitative	Activity (Tracking ID)	Previous Tracking ID, if Applicable	Target Unit	2026 Target/ Status	% Risk Reduction for 2026	2027 Target/ Status	% Risk Reduction for 2027	2028 Target/ Status	% Risk Reduction for 2028	3-Year Total	Section; Page Number
Vegetation Management and Inspections	Qualitative	Wood Management Benchmarking – (VM-23)(a)	n/a	n/a	Initiate benchmarking with peer utilities.	n/a	Gather benchmarking survey responses and facilitate discussions regarding potential alignment on best practices.	n/a	Complete implementation of any relevant updates to PG&E procedure, if applicable.	n/a	n/a	9.5; p. 386
Vegetation Management and Inspections	Qualitative	Workforce Planning – Vegetation Management (VM-24)(a)	n/a	n/a	Provide funding towards Community College towards recruitment of individuals looking to pursue a VM career path, provide funding for VM-related certifications and memberships, complete annual audit of the completion of VM Training courses.	n/a	Provide funding towards Community College towards recruitment of individuals looking to pursue a VM career path, provide funding for VM-related certifications and memberships, complete annual audit of the completion of VM Training courses.	n/a	Provide funding for VM-related certifications and memberships, complete annual audit of the completion of VM Training courses.	n/a	n/a	9.13; p. 425
Vegetation Management and Inspections	Qualitative	Integrated Vegetation Management Benchmarking (VM-25)(a)	VM-15	n/a	Initiate benchmarking with peer utilities.	n/a	Gather benchmarking survey responses and facilitate discussions regarding potential alignment on best practices.	n/a	Complete implementation of any relevant updates to PG&E procedure, if applicable.	n/a	n/a	9.7; p. 390
Vegetation Management and Inspections	Quantitative	Mitigation of Legacy Tree Removal Inventory (TRI) (VM-26)[b]	VM-04	Trees	40,000 (Cumulative)	0.94% (Cumulative)	85,000 (Cumulative)	1.99% (Cumulative)	135,000 (Cumulative)	3.16% (Cumulative)	135,000	9.4; p.384

(a) See 2026-2028 WMP Revision Notice Response R0, Critical Issue RN-PGE-26-08 for additional information.

(b) VM-26 is a cumulative target of 135,000; therefore, the 85,000 trees shown in 2027 is inclusive of the 40,000 trees from 2026. The risk reduction shown is cumulative as well. See 2026-2028 WMP Revision Notice Response R0, Critical Issue RN-PGE-26-09 for additional information.

9.1.2 Quantitative Targets

The electrical corporation must provide quantitative targets it will use to track progress on its vegetation management and inspections for the three years of the Base WMP.[147] *Every inspection activity (program) described in [Section 9.2] must have at least one quantitative target. Targets for inspection activities (programs) of overhead electrical assets must use circuit miles as the unit. Pole clearing performed in compliance with Pub. Res. Code Section 4292 must have a quantitative target. The electrical corporation may define additional pole clearing targets (e.g., pole clearing performing in the Local Responsibility Area). For each quantitative target, the electrical corporation must provide the following:*

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable;*
- *Projected targets and totals for each of the three years of the WMP cycle, e.g., [Year 1] EOY total, [Year 2] total, and [Year 3] total, 3-year total and the associated units for the targets;*
- *For inspections and pole clearing targets in Table 9-2, cumulative quarterly targets for each year of the WMP cycle*[148] *and the percentage of total overhead circuit miles in the HFTD covered by the [Year 1] target (e.g., 100 circuit miles of patrol inspections in [Year 1] divided by 300 overhead circuit miles in the HFTD equals 33 percent coverage;*
- *The expected % risk reduction for each of the three years of the WMP cycle;*[149] *and*
- *The timeline in which clearance and removal work prescribed by the inspection activity (program) will be completed (inspections and pole clearing only).*

Quantitative targets for vegetation inspection and pole clearing programs are summarized in Table 9-2 below. Additional detail is provided in the section(s) and page number(s) indicated.

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[147] *Annual information included in this section must align with the applicable data submission.*

[148] *Guidelines for WMP Update will provide additional instructions on future quarterly rolling target reporting.*

[149] *The expected % risk reduction is the expected percentage risk reduction per year, as described in Section 6.2.1.2.*

TABLE 9-2:
VEGETATION INSPECTIONS AND POLE CLEARING BY YEAR

Activity (Program)	Tracking ID	Previous Tracking ID, if applicable	Target Unit	Cumulative (Cml.) Quarterly Target 2026, Q1	Cml. Quarterly Target 2026, Q2	Cml. Quarterly Target 2026, Q3	Cml. Quarterly Target 2026, Q4	Cml. Quarterly Target 2027, Q1	Cml. Quarterly Target 2027, Q2	Cml. Quarterly Target 2027, Q3	Cml. Quarterly Target 2027, Q4	Cml. Quarterly Target 2028, Q1	Cml. Quarterly Target 2028, Q2	Cml. Quarterly Target 2028, Q3	Cml. Quarterly Target 2028, Q4	% HFTD Covered in 2026	% Risk Reduction for 2026	% Risk Reduction for 2027(a)	% Risk Reduction for 2028(a)	3-Year Total	Activity Timeline Target	Section; Page Number
Pole Clearing Program – Compliance(b)	VM-02C	VM-02	Poles(c)	13,668	30,958	45,710	45,710	13,668	30,958	45,710	45,710	13,668	30,958	45,710	45,710	4%	0.06%	0.06%	0.06%	137,130	365 days	9.4; p. 384
Pole Clearing Program – Risk Reduction(b)	VM-02R	VM-02	Poles(c)	6,820	16,445	24,290	24,290	6,820	16,445	24,290	24,290	6,820	16,445	24,290	24,290	4%	0.04%	0.04%	0.04%	72,870	365 days	9.4; p. 384
Substation Inspections – Distribution	VM-05	VM-05	Distribution Substations	58	122	130	130	58	122	130	130	58	122	130	130	100.00%	53% (Eyes on Risk)	53% (Eyes on Risk)	53% (Eyes on Risk)	390	274 days	9.6; p. 388
Substation Inspections – Transmission	VM-06	VM-06	Transmission Substations	–	53	55	55	–	53	55	55	–	53	55	55	100.00%	23% (Eyes on Risk)	23% (Eyes on Risk)	23% (Eyes on Risk)	165	274 days	9.6; p. 388
Substation Inspections – Power Generation	VM-07	VM-07	Power Generation Switchyards and Powerhouses	–	52	58	58	–	52	58	58	–	52	58	58	100.00%	24% (Eyes on Risk)	24% (Eyes on Risk)	24% (Eyes on Risk)	174	274 days	9.6; p. 388
Routine Transmission – Ground	VM-13	VM-13	Circuit Miles	1,989	10,000	15,000	17,500	1,925	10,000	15,000	17,500	1,925	10,000	15,000	17,500	100.00%	100% (Eyes on Risk)	100% (Eyes on Risk)	100% (Eyes on Risk)	52,500	365 days	9.2.3; p. 371
Transmission Hazard Patrol (Second Patrol, Tree Mortality)	VM-14	VM-14	Circuit Miles	–	–	–	5,625	–	–	–	5,625	–	–	–	5,625	100.00%	100% (Eyes on Risk)	100% (Eyes on Risk)	100% (Eyes on Risk)	16,875	365 days	9.2.4; p. 379
Distribution Routine Patrol(e)	VM-16	VM-16	Circuit Miles	11,500	31,500	50,500	78,200	11,500	31,000	50,000	77,800	11,000	31,000	50,000	77,500	100.00%	100% (Eyes on Risk)	100% (Eyes on Risk)	100% (Eyes on Risk)	233,500	365 days	9.2.1; p. 365
Distribution Hazard Patrol (Second Patrol, Tree Mortality)	VM-17	VM-17	Circuit Miles	1,500	4,000	6,500	10,000	1,500	4,000	6,500	10,000	1,500	4,000	6,500	10,000	100.00%	75.14% (Eyes on Risk)	75.14% (Eyes on Risk)	75.14% (Eyes on Risk)	30,000	365 days	9.2.2; p. 370

(a) Estimates for the 2027 & 2028 risk reduction are not available at the time of WMP submission. As such, 2026 risk reduction values will be used as a proxy.

(b) Pole Clearing Program (VM-02) is separated into Pole Clearing Program – Compliance (VM-02C) and Pole Clearing Program – Risk Reduction (VM-02R) in response to Critical Issue RN-PGE-26-10. See 2026-2028 WMP Revision Notice Response R0 for additional information.

(c) Poles are defined in this target as distribution and transmission poles and structures.

(d) Values have been updated as a result of Substantive Errata filing on April 18, 2025, in accordance with Revision Notice, Section 4. Note that the values for Pole Clearing Program – Compliance and Pole Clearing Program – Risk Reduction have since been updated in response to Revision Notice Critical Issue RN-PGE-26-10.

(e) In response to Critical Issue RN-PGE-26-09, PG&E created a target for Mitigation of Legal Tree Removal Inventory (TRI) (VM-26). See Table 9-1 for more information on VM-26. Percent Risk Reduction for 2026-2028 has been updated to reflect the removal of the VM-26 from Distribution Routine Patrol. See 2026-2028 WMP Revision Notice Response R0 for more information.

9.2 Vegetation Management Inspections

In this section, the electrical corporation must provide an overview of its vegetation management inspection activities (programs) for overhead electrical assets. This section must not include pole clearing activities or defensible space activities around substations; see Section 9.4 for pole clearing and Section 9.6 for defensible space activities around substations.

The electrical corporation must first summarize details regarding its vegetation management inspections for overhead electrical assets in Table 9-3. The table must include the following:

- *Type of Inspection: Distribution or transmission;*
- *Inspection Program Name: Identify various inspection activities (programs) within the electrical corporation (e.g., routine, enhanced vegetation, off-cycle);*
- *Area Inspected: Identify the area that the inspection activity (program) covers (e.g., territory-wide, HFTD only, Areas of Concern, etc.); and*
- *Frequency: Identify the frequency of the inspection (e.g., annual, quarterly, 3-year cycle).*

The electrical corporation must then provide a narrative overview of each vegetation inspection activity (program) identified in Table 9-3. Section 9.2.1 provides instructions for the overviews. The sections must be numbered Section 9.2.1 to Section 9.2 (i.e., each vegetation inspection activity (program) is detailed in its own section) with the name of the inspection activity (program) as the section title. The electrical corporation must include inspection activities (programs) it is discontinuing, has discontinued since the last WMP submission, or has consolidated into another activity (program) and explain why it is discontinuing or has discontinued the activity (program).

VM inspection programs for overhead electrical assets are summarized in Table 9-3 below. Additional detail is provided in the section(s) and page number(s) indicated.

TABLE 9-3:
VEGETATION MANAGEMENT INSPECTION FREQUENCY, METHOD, AND CRITERIA

Type	Inspection Activity	Area Inspected	Frequency	Section; Page Number
Distribution	Routine Patrol	Territory	Annual	9.2.1; p. 365
Distribution	Hazard Patrol (previously referred to as “Second Patrol” or “Tree Mortality”)	HFTD/HFRA	Offset from annual inspections by approximately 6 months	9.2.2; p. 370
Transmission	Routine Patrol	Territory	Annual	9.2.3; p. 374
Transmission	Hazard Patrol (previously referred to as “Second Patrol” or “Tree Mortality”)	HFTD/HFRA	Offset from annual inspections	9.2.4; p. 379

9.2.1 Distribution Routine Patrol

Tracking ID: VM-16

9.2.1.1 Overview and Area Inspected

In this section, the electrical corporation must provide an overview of the inspection activity (program). This overview must describe where the electrical corporation performs the inspection activities (programs) (e.g., territory-wide, HFTD only, Areas of Concern, etc.)

PG&E's Distribution Routine Patrol Program incorporates lessons learned from prior VM programs and WMP initiatives and leverages prioritized risk factors to inform the inspection scope. The data collected through inspections may vary based on compliance requirements, risk level, or operational needs. Inspection data collection will inform operational actions focused on minimizing vegetation-caused ignitions and interruptions.

The inspection scope of PG&E's Distribution Routine Patrol is territory-wide on overhead electric facilities (excluding service drops). The type of inspection will be informed by risk mitigation plans leveraging the enterprise Wildfire Distribution Risk Model version 4 (WDRM v4). See Section 5.2 for information about WDRM v4.

The proactive inspection scope includes patrols designed to comply with state and federal laws and regulations, including: (1) California Public Utilities Commission (CPUC) General Order (GO) 95, Rule 35; and (2) California Public Resources Code (PRC) Section 4293. See VM 16 in Table 9-2 in Section 9.1.2 for more information.

9.2.1.2 Procedures

In this section, the electrical corporation must list the procedures, including the version(s) and effective date(s), for the inspection activity (program).

The following documents describe key procedures for the Distribution Routine Patrol inspection program:[150]

- Distribution Vegetation Management Program, TD-7102S Revision 2, Effective Date 06/20/2023; and
- Vegetation Management Distribution Inspection Procedure, TD-7102P-01 (DIP) Revision 2, Effective Date 06/20/2023.

[150] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

9.2.1.3 Clearance

In this section, the electrical corporation must describe how clearances are determined and prescribed through this inspection activity (program) (e.g., GO 95 Table 1, GO 95 Appendix E, American National Standards Institute (ANSI) A-300, etc.). As applicable, the electrical corporation must describe how it differently prescribes clearances for high-risk species of vegetation.

The Distribution Routine Patrol Program performs inspections on overhead electric facilities (excluding service drops) to maintain radial clearance between vegetation and conductors. Trees that are expected to encroach within the Minimum Distance Requirement (MDR) in accordance with regulatory requirements and/or PG&E procedures are prescribed for work.

PG&E prescribes trees for work that meet the guidelines established in GO 95, which include:

- Dead, dying and declining trees, or dead portions of trees that may contact PG&E facilities if they fail;
- Green trees observed within the MDR or with the potential to encroach within the MDR before the next tree work cycle;
- Trees where PG&E has actual knowledge of strain or abrasion to secondary lines; and
- Abnormal field conditions, which may include but are not limited to: broken cross arms, floaters, objects on wires, broken branch or tree part in contact with wires, broken poles, frayed conductors, arcing wires, etc. Abnormal field conditions do not include items identified that fit the priority tag procedure (see Section 9.3.3).

PG&E's standards and procedures are informed by GO 95, Rule 35, Appendix E.. The radial clearances in Table PG&E-9.2.1.3-1 below are recommended minimum clearances that should be established at time of trimming between the vegetation and the energized conductors and associated live parts where practicable, per GO 95, Rule 35, Appendix E.

The actual clearance obtained is determined on an individual tree basis. PG&E incorporates consideration of tree species (including high-risk species) as part of its standardized work as defined in the DIP. Per the Commission's guidance in Appendix E, PG&E prescribes clearance for each tree based on factors such as line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, vegetation growth rate and characteristics, VM standards, best practices, local climate, elevation, fire risk, and vegetation trimming requirements that are applicable to State Responsibility Area (SRA) lands, pursuant to PRC Sections 4102 and 4293.

**TABLE PG&E-9.2.1.3-1:
RADIAL CLEARANCES, PER GO 95, APPENDIX E**

Voltage of Line	Case 13 of Table 1[(a)]	Case 14 of Table 1[(b)]
Radial clearances for any conductor of a line operating at 2,400 or more volts, but less than 72,000 volts	4 feet	12 feet

(a) Case 13 of Table 1: Refers to GO 95, Rule 35, , Table 1. Case 13 is radial clearance of bare line conductors from tree branches or foliage in non-HFTD.

(b) Case 14 of Table 1: Refers to GO 95, Rule 35, Table 1. Case 14 is radial clearance of bare line conductors from vegetation in the HFTD.

(c) GO 95 is available at the following link: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K438/550438485.pdf.

9.2.1.4 Fall-In Mitigation

In this section, the electrical corporation must describe how it identifies fall-in risks, such as hazard trees, during the inspection (e.g., Level 1, Level 2, etc.). As applicable, the electrical corporation must of describe how it differently prescribes removal of high-risk species of vegetation.

Identification of fall-in risks is described in the DIP. Inspectors identify fall-in risks as part of PG&E's inspection of distribution facilities in compliance with GO 95, Rule 35 and PRC Section 4293.

In accordance with the DIP, inspectors conduct Level 1 inspections during ground patrols and look for factors to trigger a detailed Level 2 inspection. The DIP provides guidance to vegetation inspectors about the factors and circumstances that trigger a Level 2 inspection and describes what a Level 2 inspection requires. The DIP describes this process as:

> *IF (while performing the Level 1 inspection) the VMI [Vegetation Management Inspector] identifies a tree or trees with conditions found in the Hazard Trees/Vegetation Clearance section of the "California Power Line Fire Prevention Field Guide" (see Appendix B, Overview of Tree Defects and Site Conditions) OR, if the VMI suspects a tree may have one or more of those conditions, THEN PERFORM a Level 2 assessment of that tree.*

Thus, a Level 2 inspection may be triggered by the identification of conditions listed in Appendix B of the DIP or at the inspector's discretion if it is suspected that any of the conditions listed in Appendix B may exist that increase the likelihood of tree failure.

The DIP provides guidance as to what a Level 2 inspection must include:

> Basic Assessment (Level 2): A detailed visual inspection of a tree and surrounding site that may include the use of simple tools. It requires that a tree risk assessor inspect completely around the tree trunk looking at the visible above ground roots, trunk, branches, and site. Level 2 inspections are ground-based.

PG&E incorporates consideration of tree species as part of its standardized work as defined in the DIP.

9.2.1.5 Scheduling

In this section, the electrical corporation must describe how the inspection activity (program) is scheduled. This must include the frequency (e.g., annual, quarterly, 3-year cycle) and/or triggers (e.g., severe weather events, risk model outputs) of the inspection program. It must also identify how the frequency and/or trigger might differ by HFTD tier or other risk designation.

If the inspection activity (program) is based on a fixed frequency (e.g., annual, 3-year cycle), the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection activity (program) to target high-risk areas). If the electrical corporation does not use risk prioritization in the scheduling of the inspection activity (program) it must explain why.

PG&E's Distribution Routine Patrol Program is focused on reducing risk of ignitions and interruptions while maintaining compliance clearance around electric lines. Inspections are conducted system-wide on an annual cycle. The inspection and corresponding tree work schedule is developed based on multiple operational factors (i.e., access due to weather conditions, agency lands, customer access, or timing requests) and is intended to be consistent year-over-year. Generally, this cadence and schedule does not differ based on HFTD or risk designation.

As described below in Section 9.2.1.6, the maturation of remote sensing technologies may impact PG&E's inspection cadence in future years, given the ability to monitor conditions on a recurring basis instead of annually.

9.2.1.6 Updates

In this section, the electrical corporation must discuss changes/updates to the inspection program since its last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

PG&E plans to adjust the Distribution Routine Patrol Program in 2026-2028 by consolidating inspection procedures and exploring use of technology to support inspections. Adjustments to the program reflect efforts to improve customer sentiment (i.e., reducing customer touchpoints) and feedback from external stakeholders (i.e., areas of continuous improvement). Each update is described in the bullets below.

- Consolidating inspection programs:
  - In the 2023-2025 WMP, PG&E described the three following programs in addition to the Distribution Routine Patrol Program:
    - Focused Tree Inspection (FTI);
    - Tree Removal Inventory (TRI); and
    - Vegetation Management for Operational Mitigations (VMOM).
  - PG&E is in the process of evaluating which component(s) of the FTI and TRI scope will be incorporated into the Distribution Routine Patrol Program. This analysis will be based on findings from efficacy studies planned to be performed in 2025. See Revision Notice Response to Critical Issue RN-PGE-26-09 for additional information. PG&E will incorporate VMOM into activities described in Section 9.9.1.
- Exploring the use of technology to support inspections:
  - In 2025, PG&E will use data gathered from proven remote sensing technologies to analyze how distribution inspections could be further evolved to incorporate remote sensing techniques.
  - Remote sensing techniques that will be considered could include satellite, Light Detection and Ranging (LiDAR), ortho imagery, or other available technology that can provide accurate and efficient insights into vegetation risk.
  - PG&E may consider utilizing remote sensing in lieu of ground-based inspections on electrical spans that typically have no trees around the lines, to provide customers with a more cost-effective solution. This is based off the comparison of remote sensing detections versus ground-based identification in locations that typically have no or limited trees with the potential to impact PG&E facilities.

9.2.2 Distribution Hazard Patrol

Tracking ID: VM-17

9.2.2.1 Overview and Area Inspected

In this section, the electrical corporation must provide an overview of the inspection program. This overview must describe where the electrical corporation performs the inspection programs (e.g., territory-wide, HFTD only, Areas of Concern, etc.)

PG&E's Distribution Hazard Patrol (previously second patrol, tree mortality) Program consists of additional proactive inspections conducted in high-risk areas based on a risk-prioritized approach. These inspections focus on overhead distribution facilities (excluding service drops) in a risk-prioritized subset of the HFTD and HFRA and are offset by approximately six months from the Distribution Routine Patrol.

This program will primarily focus on high wildfire risk and consequence locations, targeting tree work identification in the highest-consequence parts of the system. The areas of the Distribution Hazard Patrol Program are informed by the WDRM v4. See Section 5.2 for more information on PG&E's WDRM v4. The HFTD and HFRA locations in scope for the Distribution Hazard Patrol Program are based on a holistic approach to inspections intended to increase eyes-on-risk at locations with the highest wildfire risk or consequence of a wildfire. Similar to Electric Asset Inspections, PG&E utilizes a 5x5 matrix of wildfire consequence and WDRM v4 to identify such locations. The wildfire risk dimension is consistent with identifying previous areas of concern. The consequence dimension is used in addition to risk to prioritize inspections in locations where any event could be catastrophic, but the probability of failure is determined based on the inspection itself.

Figure PG&E 9.2.2.1-1 depicts the risk and consequence categories: Extreme, Severe, High, Medium, and Low. Distribution Hazard Patrols will occur in the Extreme, Severe, High, and Medium categories. Where opportune based on the maturity of remote sensing technologies, PG&E will conduct additional remote sensing-based inspections in the Extreme, Severe, and High categories for further eyes on risk.

FIGURE PG&E-9.2.2.1-1:
INSPECTION SELECTION MATRIX

Eyes on Risk[3] Selection Process
Unit: Number of miles

Consequence[1]					
Extreme	7	24	70	3	61
Severe	33	84	147	37	23
High	631	1,061	1,447	221	96
Medium	2,395	1,344	1,013	86	20
Low	13,875	1,704	432	4	1
	Low	**Medium**	**High**	**Severe**	**Extreme**
	Wildfire Risk[2]				

Routine/Hazard/ Remote Sensing *Routine/Hazard* *Routine*

See VM-17 in Table 9-2 in Section 9.1.2 for more information.

9.2.2.2 Procedures

In this section, the electrical corporation must provide a list of the procedures, including the version(s) and effective date(s), for the inspection program.

The following documents describe key procedures for the Distribution Hazard Patrol Program:[151]

- Distribution Vegetation Management Program, TD-7102S Revision 2, Effective Date 06/20/2023; and
- Vegetation Management Distribution Inspection Procedure, TD-7102P-01 Revision 2, Effective Date 06/20/2023.

151 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

9.2.2.3 Clearance

In this section, the electrical corporation must describe how clearances are determined and prescribed through this inspection program (e.g., GO 95 Table 1, GO 95 Appendix E, ANSI A-300, etc.). As applicable, the electrical corporation must describe how it differently prescribes clearances to high-risk species of vegetation.

The clearance determination processes for the Distribution Hazard Patrol Program are the same as described in Section 9.2.1.3.

9.2.2.4 Fall-In Mitigation

In this section, the electrical corporation must describe how it identifies fall-in risks, such as hazard trees, during the inspection (e.g., Level 1, Level 2, etc.). As applicable, the electrical corporation must of describe how it differently prescribes removal of high-risk species of vegetation.

The fall-in mitigation processes for the Distribution Hazard Patrol Program are the same as described in Section 9.2.1.4.

9.2.2.5 Scheduling

In this section, the electrical corporation must describe how the inspection program is scheduled. This must include the frequency (e.g., annual, quarterly, 3-year cycle) and/or triggers (e.g., severe weather events, risk model outputs) of the inspection program. It must also identify how the frequency and/or trigger might differ by HFTD tier or other risk designation.

If the inspection program is based on a fixed frequency (e.g., annual, 3-year cycle), the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection program to target high-risk areas). If the electrical corporation does not use risk prioritization in the scheduling of the inspection program, it must explain why.

PG&E's Distribution Hazard Patrol Program is conducted on a risk-prioritized subset of locations at an approximately six-month offset from the Distribution Routine Patrol. See Section 9.2.1.5 above for a description of the scheduling for the Distribution Routine Patrol Program.

9.2.2.6 Updates

In this section, the electrical corporation must discuss changes/updates to the inspection program since its last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

PG&E's Distribution Hazard Patrol Program has evolved from "CEMA – Dead and Dying (Tree Mortality)," to Second Patrol.

PG&E is transitioning the Distribution Hazard Patrol Program scope from focusing on all HFTD and HFRA locations to focusing on areas categorized by risk, which may represent a subset of HFTD miles.

PG&E may consider utilizing remote sensing to supplement or in lieu of ground-based inspections on PG&E facilities.

9.2.3 Transmission Routine Patrol

Tracking ID: VM-13

9.2.3.1 Overview and Area Inspected

In this section, the electrical corporation must provide an overview of the inspection program. This overview must describe where the electrical corporation performs the inspection programs (e.g., territory-wide, HFTD only, Areas of Concern, etc.)

PG&E's Transmission Routine Patrol Program spans all transmission lines across PG&E's service territory and consists of several different methods for inspecting vegetation in proximity to transmission facilities. The program scope is organized into North American Electric Reliability Corporation (NERC) and non-NERC inspections. This program helps us safely and reliably operate transmission facilities while complying with the applicable laws and regulations. See VM-13 in Table 9-2 in Section 9.1.2 for more information.

The Transmission Routine NERC Patrol includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments on approximately 6,800 miles of NERC-critical facilities. One hundred percent of inspection and work plan completion is required by NERC Standard FAC-003-5[152] within a calendar year.

The Transmission Routine Non-NERC Patrol includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments and other vegetation conditions on approximately 11,400 miles of transmission facilities not designated as critical by NERC.

The Transmission Routine NERC and Non-NERC Patrol cycles consist of a LiDAR inspection followed by a ground patrol based on LiDAR detections. When ground patrols are completed, work is categorized by the level of urgency outlined in Section 9.3.3.

9.2.3.2 Procedures

In this section, the electrical corporation must provide a list of the procedures, including the version(s) and effective date(s), for the inspection program.

The following documents describe key procedures for the Transmission Routine Patrol Program:

- Vegetation Management Transmission Program, TD-7103S Revision 4, Effective date 1/27/2025; and

[152] The supporting document is available at: PG&E's Community Wildfire Safety Program.

- Vegetation Management Transmission Inspection TD-7103P-01 Revision 4, Effective date 1/27/2025.

9.2.3.3 Clearance

In this section, the electrical corporation must describe how clearances are determined and prescribed through this inspection program (e.g., GO 95 Table 1, GO 95 Appendix E, ANSI A-300, etc.). As applicable, the electrical corporation must describe how it differently prescribes clearances to high-risk species of vegetation.

PG&E's Transmission Routine Patrol Program maintains vegetation clearance in accordance with GO 95, Rule 35, PRC Section 4293, NERC Standard for Transmission Vegetation Management FAC-003-5, and other applicable regulations.

PG&E minimum clearance distances are shown in Table PG&E-9.2.3.3-1 below.

TABLE PG&E-9.2.3.3-1:
PG&E MINIMUM CLEARANCE DISTANCES

	60 or 70 kilovolts (kV)	115 kV	230 kV	500 kV
PG&E Minimum Clearance Distance	4 feet (ft.)	10 ft.	10 ft.	15 ft.

Note: The PG&E defined minimum clearance distances are designed to meet or exceed all applicable regulatory requirements, including NERC Standard FAC-003-5, PRC 4293 and CPUC GO 95, Rule 35.

CPUC minimum clearance distance requirements and recommendations are shown in Table PG&E-9.2.3.3-2 below.

TABLE PG&E-9.2.3.3-2:
CPUC MINIMUM CLEARANCE DISTANCE REQUIREMENTS AND RECOMMENDATIONS

	60 or 70 kV	115 kV	230 kV	500 kV
CPUC Requirement in non-HFTD (Case 13)	1 ft. 6 in.	1 ft.7 in.	2 ft 6.5 in.	9 ft.7 in.
CPUC Recommendation at Time of Trim	4 ft.	10 ft.	10 ft.	15 ft.
CPUC Requirement in HFTD (Case 14)	4 ft.	10 ft.	10 ft.	10 ft.
CPUC Recommendation at Time of Trim in HFTD	12 ft.	30 ft.	30 ft.	30 ft.

Note: The CPUC minimum clearance distances are in CPUC GO 95, Table 1 and Appendix E. Reasonable vegetation practices may make it advantageous for the purpose of public safety or service reliability to obtain greater clearances than those in this table to ensure compliance until the next scheduled maintenance.

NERC Minimum Vegetation Clearance Distance (MVCD) is shown in Table PG&E-9.2.3.3-3 below.

TABLE PG&E-9.2.3.3-3:
NERC MINIMUM VEGETATION CLEARANCE DISTANCE (MVCD) IN FEET

Elevation (feet)	60/70 kV	115 kV	230 kV	500 kV
0-500	1.1 ft.	1.9 ft.	4.0 ft.	7.0 ft
501-1,000	1.1	1.9	4.1	7.1
1,001-2,000	1.1	1.9	4.2	7.2
2,001-3,000	1.2	2.0	4.3	7.4
3,001-4,000	1.2	2.0	4.3	7.5
4,001-5,000	1.2	2.1	4.4	7.6
5,001-6,000	1.2	2.1	4.5	7.8
6,001-7,000	1.3	2.2	4.6	7.9
7,001-8,000	1.3	2.2	4.7	8.1
8,001-9,000	1.3	2.3	4.8	8.2
9,001-10,000	1.4	2.3	4.9	8.3
10,001-11,000	1.4	2.4	5.0	8.5
11,001-12,000	1.4	2.5	5.1	8.6
12,001-13,000	1.5	2.5	5.2	8.8
13,001-14,000	1.6	2.6	5.3	8.9
14,001-15,000	1.6	2.7	5.4	9.1

9.2.3.4 Fall-In Mitigation

In this section, the electrical corporation must describe how it identifies fall-in risks, such as hazard trees, during the inspection (e.g., Level 1, Level 2, etc.). As applicable, the electrical corporation must of describe how it differently prescribes removal of high-risk species of vegetation.

Identification of fall-in risks is described in the Vegetation Management Transmission Program procedure. Inspectors identify fall-in risks as part of PG&E's inspection of transmission facilities in compliance with GO 95, Rule 35, NERC Standard FAC-003-05 and PRC Section 4293. PG&E incorporates consideration of tree species (including high-risk species) as part of its standardized work as defined in the Vegetation Management Transmission Program procedure.

9.2.3.5 Scheduling

In this section, the electrical corporation must describe how the inspection program is scheduled. This must include the frequency (e.g., annual, quarterly, 3-year cycle) and/or triggers (e.g., severe weather events, risk model outputs) of the inspection program. It must also identify how the frequency and/or trigger might differ by HFTD tier or other risk designation.

If the inspection program is based on a fixed frequency (e.g., annual, 3-year cycle), the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection program to target high-risk areas). If the electrical corporation does not use risk prioritization in the scheduling of the inspection program, it must explain why.

Transmission Routine NERC patrol and Transmission Routine Non-NERC projects are annually recurring. The inspection of NERC projects is required by NERC Standard FAC-003-5 to be completed within a calendar year. The inspection of Routine projects located in HFTD/HFRA areas are prioritized in the schedule. The schedule is developed based on multiple operational factors (i.e., access due to weather conditions, agency lands, customer access or timing requests).

9.2.3.6 Updates

In this section, the electrical corporation must discuss changes/updates to the inspection program since its last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

There are no updates to the Transmission Routine Patrol Program since the last WMP submission.

While the current program has successfully utilized LiDAR for inspection detections, PG&E continues to explore various remote sensing technologies (i.e., satellite) as it continues to mature. As PG&E identifies opportunities to use alternatives instead of LiDAR, PG&E may shift inspection technologies or use other inspection technologies to supplement its current inspection processes and practices.

9.2.4 Transmission Hazard Patrol

Tracking ID: VM-14

9.2.4.1 Overview and Area Inspected

In this section, the electrical corporation must provide an overview of the inspection program. This overview must describe where the electrical corporation performs the inspection programs (e.g., territory-wide, HFTD only, Areas of Concern, etc.)

PG&E's Transmission Hazard Patrol (Previously Second Patrol, Tree Mortality) consists of an ortho-imagery patrol offset from the Transmission Routine Patrol Program in HFTD/HFRA areas. See VM-14 in Table 9-2 in Section 9.1.2 for more information.

9.2.4.2 Procedures

In this section, the electrical corporation must provide a list of the procedures, including the version(s) and effective date(s), for the inspection program.

The following documents describe key procedures for the Transmission Hazard Patrol Program:

- Vegetation Management Transmission Program, TD-7103S Revision 4, Effective date 1/27/2025; and
- Vegetation Management Transmission Inspection, TD-7103P-01 Revision 4, Effective date 1/27/2025.

9.2.4.3 Clearance

In this section, the electrical corporation must describe how clearances are determined and prescribed through this inspection program (e.g., GO 95 Table 1, GO 95 Appendix E, ANSI A-300, etc.). As applicable, the electrical corporation must describe how it differently prescribes clearances to high-risk species of vegetation.

The clearance determination processes for the Transmission Hazard Patrol Program are the same as described in Section 9.2.3.3.

9.2.4.4 Fall-In Mitigation

In this section, the electrical corporation must describe how it identifies fall-in risks, such as hazard trees, during the inspection (e.g., Level 1, Level 2, etc.). As applicable, the electrical corporation must of describe how it differently prescribes removal of high-risk species of vegetation.

The fall-in mitigation processes for the Transmission Hazard Patrol Program are the same as described in Section 9.2.3.4.

9.2.4.5 Scheduling

In this section, the electrical corporation must describe how the inspection program is scheduled. This must include the frequency (e.g., annual, quarterly, 3-year cycle) and/or triggers (e.g., severe weather events, risk model outputs) of the inspection program. It must also identify how the frequency and/or trigger might differ by HFTD tier or other risk designation.

If the inspection program is based on a fixed frequency (e.g., annual, 3-year cycle), the electrical corporation must explain how it uses risk prioritization in the scheduling of the inspection program to target high-risk areas). If the electrical corporation does not use risk prioritization in the scheduling of the inspection program, it must explain why.

Inspections for PG&E's Transmission Hazard Patrol Program are conducted on all overhead electric transmission facilities (including idle) in defined geographic areas of HFTD and HFRA. The Transmission Hazard Patrol Program inspects for changing tree conditions that are expected to require vegetation work before the next annual routine inspection (which is tree-specific but typically around six-months from the date of routine inspection). See Section 9.2.3.5 above for a description of the scheduling for routine inspections.

9.2.4.6 Updates

In this section, the electrical corporation must discuss changes/updates to the inspection program since its last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

There are no updates to the Transmission Hazard Patrol Program since the last WMP submission. PG&E is exploring transitioning the Transmission Hazard Patrol Program scope from focusing on all HFTD and HFRA locations to focusing on areas categorized by risk, which may represent a subset of HFTD miles.

PG&E continues to explore various remote sensing technologies (i.e., satellite) as those technologies continue to mature. As PG&E identifies opportunities to use alternatives, PG&E may shift inspection technologies or use other inspection technologies to supplement its current inspection processes and practices.

9.3 Pruning and Removal

Tracking ID: N/A

9.3.1 Overview

In this section, the electrical corporation must provide an overview of the subsequent pruning, removal, and other vegetation management activities that are performed as a result of inspections.

PG&E's pruning and removal activities leverage industry-wide and PG&E's own leading VM practices. These activities also adhere to regulatory requirements regarding vegetation maintenance around overhead electric facilities.

Pruning and removal activities include the management of vegetation based on PG&E's standards and procedures and to meet clearances outlined in PG&E's MDR.

When pruning and removal activities are required, PG&E follows industry standards and arboriculture practices. Industry standards include International Society of Arboriculture (ISA) Best Management Practices (BMP), ANSI A300 Part 9, "Tree Risk Assessment Standard," and companion publication "Utility Tree Risk Assessment," Cal Fire Power Line Fire Prevention Field Guide, and Utility Arborist Association (UAA) Best Management Practices for Tree Risk Assessment.[153]

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[153] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

9.3.2 Procedures

In this section, the electrical corporation must list the procedures, including the version(s) and effective date(s), for subsequent pruning, removal, and other vegetation management activities that are performed as a result of inspections.

The following documents describe key procedures related to PG&E's vegetation pruning and removal activities:[154]

- Distribution Vegetation Management Program, TD-7102S Revision 2, Effective Date 06/20/2023;
- Vegetation Management Distribution Inspection Procedure, TD-7102P-01 (DIP) Revision 2, Effective Date 06/20/2023;
- Vegetation Management Transmission Program, TD-7103S Revision 4, Effective date 1/27/2025;
- Vegetation Management Transmission Inspection TD-7103P-01 Revision 4, Effective date 1/27/2025;
- Transmission Vegetation Management Imminent Threat and Hazard Notification, TD-7103P-09 Revision 7, Effective date 04/24/2025; and
- Vegetation Management Priority Tag, TD-7102P-17 Revision 3, Effective date 01/27/2025.

9.3.3 Scheduling

In this section, the electrical corporation must describe how subsequent pruning, removal, and other vegetation management activities that are performed as a result of inspections are scheduled. This must include the timeline(s) in which clearance and removal work prescribed by an inspection activity (program) will be completed and how the timeline differs by HFTD tier or other risk designation.

PG&E applies the following timelines once tree work has been prescribed by a patrol program, unless constrained as outlined below and in the applicable procedures. These timelines are not impacted by HFTD tier.

For Distribution:

- Priority Level 1 (P1) tags must be mitigated within 24 hours of inspection unless an approved mitigation plan is in place.

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[154] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

- Priority Level 2 (P2) tags must be mitigated within 20 business days of inspection, unless constrained.

- Beginning in the 2024 inspection cycle, unless a constraint or external factor is documented, non-priority tree work shall be completed within one year of identification.

For Transmission:

- Imminent Threat: Imminent is vegetation affecting NERC transmission facilities and likely to cause a fault at any moment. Mitigation to be completed within 24 hours of notification.

- Hazard Notification – Immediate (HN-I): Vegetation within the PG&E minimum clearance requirements. It also includes vegetation that poses an immediate threat to the conductors or is actively failing or otherwise presents an immediate risk to electric overhead facilities. Mitigation to be completed within 24 hours of notification, unless constrained.

- Hazard Notification – Urgent (HN-U): A condition where vegetation is at or approaching the PG&E minimum clearance requirements or vegetation which requires near-term mitigation. Mitigation to be completed within 20 business days of being reported to a PG&E employee, unless constrained.

- Non-Priority Vegetation That Is Not Imminent Threat, HN-I or HN-U: Mitigation to be completed prior to the next scheduled patrol, unless constrained.

- Identified tree work for NERC facilities must be completed within the calendar year, unless there are exceptions that meet the acceptable variance criteria (NERC Standard FAC-003-5 Requirement 7).

9.3.4 Updates

In this section, the electrical corporation must discuss changes/updates to pruning and removal activities since the last WMP submission, including known future plans (beyond the current year) and new/novel strategies the electrical corporation may implement in the next five years (e.g., references to and strategies from pilot projects and research). The electrical corporation must include lessons learned as applicable.

There are no updates to PG&E's pruning and removal activities since the last WMP submission, unless otherwise described above in the distribution and transmission programs. To further develop a risk-informed approach to tree work and help to expedite tree work completion in certain parts of the service territory, PG&E is examining work prioritization categories beyond the P1, P2, and Routine designation

9.4 Pole Clearing

Tracking ID: VM-02C, VM-02R

9.4.1 Overview

In this section, the electrical corporation must provide an overview of pole clearing, including:

- *Pole clearing performed in compliance with Pub. Res. Code Section 4292; and*
- *Pole clearing outside the requirements of Pub. Res. Code Section 4292 (e.g., pole clearing performed outside of the State Responsibility Area).*

PG&E removes vegetation to maintain firebreaks around select transmission and distribution poles and towers, in accordance with PRC Section 4292. Per California Code of Regulation (CCR) Title 14, Section 1254, PG&E removes/clears flammable vegetation and materials, brush, limbs and foliage in a 10 ft radius around the applicable poles and towers from 0 to 8 feet above the ground and removes/clears all dead and dying vegetation from 8 ft up from the ground to the top of the conductor. Per 14 CCR Section 1252, PRC Section 4292 applies to any mountainous land, forest-covered land, brush-covered land or grass-covered land within SRAs, unless specifically exempted by 14 CCR 1255 and 1257. PRC 4292 has also been adopted by Region 5 of the United States Forest Service (USFS). PRC 4292 mandates pole clearing requirements for poles or towers which support a switch, fuse, transformer, lightning arrester, line junction, or dead end or corner poles, unless otherwise exempted by 14 CCR Section 1255. In response to Critical Issue RN-PGE-26-10, PG&E has separated the existing target, VM-02, into two new targets for the years 2026 through 2028, Pole Clearing Program – Compliance target (VM-02C) and Pole Clearing Program – Risk Reduction target (VM-02R). See Revision Notice Response to Critical Issue RN-PGE-26-10 for additional information. See VM-02C and VM-02R in Table 9-2 in Section 9.1.2 for more information.

PG&E maintains additional firebreaks at non-SRA, non-USFS Federal Responsibility Area (FRA) poles in certain areas of HFTD and HFRA. These additions are based on PG&E guidance (e.g., risk reduction work) or through local agreements. The additional locations are intended to reduce risk, improve access to equipment, allow for safe Supervisory Control and Data Acquisition (SCADA) operations, enhance public safety, supplement other mitigations, and protect assets from wildfires regardless of cause at equipment locations.

9.4.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used to execute pole clearing.

The following documents describe key procedures for the Pole Clearing initiative:[155]

- Vegetation Control Program, TD-7112S Revision 2, Effective date 07/03/2024; and
- Vegetation Control, TD-7112P-01 Revision 1, Effective date 07/03/2024.

9.4.3 Scheduling

In this section, the electrical corporation must describe how pole clearing is scheduled. This must include how the schedule is affected by HFTD tier or other risk designation.

Pole Clearing work is conducted throughout the year depending on the equipment and location of the poles:

- All primary-voltage, distribution subject poles/equipment within SRA, USFS-FRA, HFTD, and HFRA are inspected. The inspection cycle is generally from October-March.
- All subject poles that are not constrained or within 14 CCR Section 1255 exempt status are cleared before the start of fire season, which is considered the initial clear. Pole clearing generally starts in January and goes through the end of April, before wildfire season.
- All subject poles that are not constrained or within 14 CCR Section 1255 exempt status are re-cleared during maintenance cycles. Maintenance cycles generally run from May through December, throughout wildfire season.
- Transmission poles with switches, which are identified by the Enterprise Geographic Information System team, are cleared and are treated as compliance work throughout SRAs, USFS-FRAs, and other areas assigned by PG&E within the HFTD/HFRA.

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155 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

9.4.4 Updates

In this section, the electrical corporation must describe changes to pole clearing since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to pole clearing and the timeline for implementation.

In prior years, the initial pole clearing work started in sync with the pole clearing inspection in the prior year. To improve and maintain compliance, PG&E changed the pole clearing program in 2025 to include a second maintenance cycle from September through December. This change shortens the clearing gaps between initial clearing and maintenance cycles and reduces the amount of regrowth between clearing cycles.

9.5 Wood and Slash Management

Tracking ID: VM-23

9.5.1 Overview

In this section, the electrical corporation must provide an overview of how it manages all downed wood and slash generated from vegetation management activities.

Through its Wood Management (WM) Program, PG&E chips, relocates, or hauls away wood resulting from trees worked by PG&E VM programs. WM is conducted in a manner that ensures site safety and environmental compliance following VM tree work.

Vegetative material is a byproduct of VM work. Material less than four inches in diameter, sometimes referred to as “brush” or “slash,” will be referred to as “debris” for consistency purposes. Typical treatment methods for debris include chipping and hauling or lopping and scattering in accordance with industry-leading practices. In some instances, PG&E will leave chips on site at the request of the property owner.

Vegetative material resulting from tree work that is greater than four inches in diameter is referred to as “wood.” Wood belongs to and is the responsibility of the property owner and typically remains on site in a safe location. If the wood meets qualifying criteria as outlined in PG&E’s procedures, PG&E may offer wood management in response to customer requests. If wood management is conducted, property owner authorization is obtained.

The scope of wood management may include relocating wood onsite or hauling wood offsite and typically focuses on wood adjacent to structures, outbuildings, propane tanks, and roads. In all cases, if relocating or hauling wood poses a safety risk or environmental, cultural or access concern, the wood will remain in its current location.

PG&E’s WM activities are designed to support customer efforts to maintain compliance with PRC Section 4291, which requires property owners to maintain defensible space. Unlike PRC 4291, the scope of our WM Standard and Procedure extends beyond SRAs to our entire service area, ensuring all PG&E customers have equitable access to this level of support where appropriate. The scope of our wood management Standard and Procedure extends to our entire service area, ensuring all PG&E customers have equal access to this level of support.

PG&E is developing peer utility wood management benchmarking to identify best practices. As requested, ACI PG&E-23B-16 describes our benchmarking to date. Future benchmarking may yield opportunities for subsequent standard and procedure updates, as appropriate. See VM-23 in Table 9-1 in Section 9.1.1 for more details. See also Revision Notice Response to Critical Issue RN-PGE-26-08 for additional information.

9.5.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used to manage wood and slash.

The following documents describe key procedures for Wood and Slash Management:[156]

- Vegetation Management Wood Management Program, TD-7116S Revision 1, Effective date 01/27/2025; and
- Vegetation Management Wood Management Inspection and Prescription, TD-7116P-01 Revision 1, Effective date 01/27/2025.

9.5.3 Scheduling

In this section, the electrical corporation must describe how wood and slash management is scheduled. This must include how the schedule is affected by HFTD tier or other risk designation.

Debris management is completed in coordination with tree work across PG&E's service area. Wood management that is necessary to address public safety, environmental or critical access concerns is completed in coordination with associated tree work across PG&E's service area. Wood management that is conducted in response to a customer request is typically completed within 90 days of tree work project completion across PG&E's service area, unless affected by weather, field conditions, or other constraints.

[156] The supporting documents are available at: PG&E’s Community Wildfire Safety Program.

9.5.4 Updates

In this section, the electrical corporation must describe changes to wood and slash management since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to wood and slash management and the timeline for implementation.

PG&E now applies its wood management activities on a case-by-case basis in response to customer requests for distribution vegetation management work. Updates are reflected in Utility Standard TD-7116S and Utility Procedure TD-7116P-01, which replaced Utility Procedure TD-7102P-26.

9.6 Defensible Space

Tracking ID: VM-05; VM-06; VM-07

9.6.1 Overview

In this section, the electrical corporation must provide an overview of its action taken to reduce wildfire risk to substations, generation facilities, and other electrical facilities in accordance with Pub. Res. Code Section 4291, other defensible space codes and regulations, or in exceedance of these requirements.

PG&E's Defensible Space Inspection initiatives identify potential flammable fuels and vegetation for mitigation, in accordance with PRC Section 4291. PG&E applies these initiatives to distribution and transmission Electric Substations and Power Generation Switchyards in HFTD /HFRA. The initiatives include inspections, removal, and mitigation work to minimize the potential for ignitions spreading from substation and switchyard facilities. These initiatives provide improved structure-defense capability for firefighting purposes, by maintaining a safe distance between vegetation and critical infrastructure. Defensible space both provides outward fire-spread mitigation and also protects substation and switchyard infrastructure against an incoming fire. See VM-05; VM-06; VM-07 in Table 9-2 in Section 9.1.2 for more information.

This mitigation includes the removal of dead, dying, or diseased vegetation, where permitted, based on results and findings from substation defensible space inspections.[157] Remaining vegetation is mowed, pruned, and trimmed to reduce ladder or flash fuels. Issues that pose a vegetation-related ignition risk identified during defensible space inspections are documented in inspection reports and subsequently mitigated.

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[157] After cutting back vegetation, PG&E may remove the debris from the property or may chip, masticate, lop, and scatter material which is then left behind. Both actions minimize the risk of ignition spread and provide improved defensible space between vegetation and critical infrastructure.

9.6.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used to create and maintain defensible space.

The following document describes key procedures for the Defensible Space program:[158]

- Electric Substation and Power Generation Powerhouse and Switchyard Defensible Space, LAND-5201P-01 Revision 4, Effective date 3/05/2025.

9.6.3 Scheduling

In this section, the electrical corporation must describe how creation and maintenance of defensible space are scheduled. This must include how the schedule is affected by HFTD tier or other risk designation.

Electric substation and power generation switchyard inspections and associated mitigation are generally prioritized by HFTD Tier designation annually. Generally, Tier 3 sites are prioritized before Tier 2 HFTD and HFRA sites. There are conditions that may delay inspections and mitigation of some Tier 3 HFTD sites until later into the year after some Tier 2 HFTD or HFRA sites have been completed. Conditions that may disrupt the sequence of inspection and mitigation priorities could include access issues, severe weather, permitting issues, and prioritization of certain sites due to significant vegetation growth.

9.6.4 Updates

In this section, the electrical corporation must describe changes to how it creates or maintains defensible space since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to defensible space and the timeline for implementation.

Beginning in 2024, Electric Operations (EO) and Power Generation (PG) aligned under a single defensible space procedure, Electric Substation and Power Generation Powerhouse and Switchyard Defensible Space (LAND-5201P-01). This procedure includes an evaluation of the risk associated with unique situations at co-located PG&E switchyard and EO substation sites that inhibit the ability to achieve full defensible space as defined in LAND-5201P-01. The evaluation process brings together Safety and Infrastructure Protection Team (SIPT) members, Power Generation and substation

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[158] The supporting document is available at: PG&E's Community Wildfire Safety Program.

fire marshals, and Natural Resource Management (NRM) team members to help evaluate and align on the risk and make recommendations if further mitigations are required.

9.7 Integrated Vegetation Management

Tracking ID: VM-25

9.7.1 Overview

In this section, the electrical corporation must provide an overview of its actions taken for activities not covered in previous sections and performed in accordance with Integrated Vegetation Management principles. This may include, but is not limited to, the following activities: the strategic use of herbicides, growth regulators, or other chemical controls; tree-replacement activities (programs) promotion of native shrubs; prescribed fire; or other fuel treatment activities.

PG&E's Integrated Vegetation Management (IVM) activities utilize vegetation management practices to reduce wildfire and outage risk by preventing vegetation encroachment near PG&E assets. IVM activities include vegetation control, a tree replacement program, and community education.

IVM control methods may include a combination of chemical, biological, mechanical, manual or cultural (management of vegetation through alternative land uses) treatments. PG&E primarily uses manual, mechanical, and chemical methods to support the goal of removing incompatible trees and encouraging the growth of low-growing, compatible species.

PG&E's Right Tree, Right Place Program pairs a tree replacement giveaway program with community education by promoting safe planting practices near PG&E overhead and underground powerlines, gas pipelines and other PG&E assets. Through community events, planting guides and other educational materials, customers are empowered to choose the right tree for the right location which helps provide future benefits by reducing the volume of trees that will require maintenance. The Right Tree, Right Place Program includes a tree replacement program where a customer or community is provided replacement compatible trees that can more safely grow near PG&E assets.

PG&E's Transmission Integrated Vegetation Management (TIVM) Program provides maintenance on previously treated Transmission right-of-way (ROW) corridors. After the initial IVM work is performed, the ROWs are reassessed periodically, and maintenance work may be planned based on the following inputs:

- TIVM LiDAR data, which assesses vegetation conditions by electric transmission lines (ETL);
- Past right-of-way clearing project completion status;
- TIVM project completion history;

- Agency and landowner agreements or commitments;
- HFTD/HFRA designation; and
- Carryover work from the previous year(s).

PG&E is developing a peer utility Integrated Vegetation Management benchmarking study to identify best practices. See VM-25 in Table 9-1 in Section 9.1.1 for more details. See also Revision Notice Response to Critical Issues RN-PGE-26-08 and RN-PGE-26-11 for additional information.

9.7.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used for integrated vegetation management.

The following documents describe key procedures for the Integrated Vegetation Management Right-of-Way Maintenance Program:

- Vegetation Management Transmission ROW Maintenance and ROW Expansion Programs, TD-7111S Revision 1, Effective date 04/20/2024
- Transmission Integrated Vegetation Management Right-of-Way Maintenance, TD-7111P-01 Revision 0, Effective date 04/20/2024.
- See the Right Tree, Right Place website for more information: https://www.pge.com/en/outages-and-safety/safety/yard-safety.html

9.7.3 Scheduling

In this section, the electrical corporation must describe how integrated vegetation management activities are scheduled. This must include how the schedule is affected by HFTD tier or other risk designation.

IVM activities are scheduled based on the type of activity. The Right Tree, Right Place Program is a year-round community education and tree replacement program and is independent of HFTD tier or other risk designation.

PG&E schedules TIVM ROW maintenance program activities based on the outputs of the work plan development described in the program overview. TIVM focuses on established Transmission-ROW corridors. Where feasible, the TIVM Program implements wire zone border zone management, which promotes low growing vegetation underneath conductors. These treatments can reduce overall fuel loading and continuity of fuels, which may reduce risk and possibly make safe anchor points for fire responders.

For TIVM, previously worked ROWs are reassessed every 2-5 years. The quantity of TIVM work varies by year, depending upon resources available. Scheduling is influenced by several factors including, but not limited to, the following:

- Operational factors, which may include access due to weather conditions, agency lands, customer access or timing requests;
- Projected efficacy of chemical control methods (i.e., herbicide application generally occurs in Q3 and Q4); and
- HFTD/HFRA designation where work may be prioritized.

9.7.4 Updates

In this section, the electrical corporation must describe changes to its integrated vegetation management activities since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to integrated vegetation management and the timeline for implementation.

No changes or improvements are planned for PG&E's IVM activities. For the 2026-2028 WMP, PG&E replaced the previous quantitative IVM initiative (VM-15) with a qualitative IVM initiative to benchmark with peer utilities (VM-25). It is difficult to define a quantitative target for PG&E's IVM activities, as they span multiple programs, may overlap with other initiatives, and will vary in scope each year depending on resources and demand.

9.8 Partnerships

Tracking ID: N/A

In this section, the electrical corporation must provide information on its partnerships with other entities in vegetation management. This may include partnerships with government agencies, non-profit organizations, or coalitions, such as Regional Forest and Fire Capacity Program grantees and local forest collaboratives.[159] *For this section, "partnership" is defined as the combining of resources, expertise, and efforts to accomplish agreed upon objectives related to wildfire risk reduction achieved through vegetation management. The electrical corporation must provide the following summary information in table format for current partnerships and future partnerships the electrical corporation plans to enter during the three years of the WMP cycle:*

- *Names of all agencies, organizations, or coalitions in the partnership.*

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[159] *Regional Forest and Fire Capacity Program, available at: https://www.conservation.ca.gov/dlrp/grant-programs/Pages/Regional-Forest-and-Fire-Capacity-Program.aspx.*

- *Vegetation management activities performed pursuant to or under the partnership (e.g., thinning, prescribed fire, mastication, invasive plant removal, woody debris management, etc.).*

- *The objective of the activities performed pursuant to or under the partnership.*

- *Electrical corporation's role in the coordination or partnership (e.g., funding, labor, landowner, etc.).*

- *Anticipated accomplishments of partnership projects during the three years of the WMP cycle, including work done by the electrical corporation and work done by the partnering agency/organization (e.g., number of acres treated, number of trees planted, number of personnel trained, etc.).*

PG&E's partnerships with other entities as related to vegetation management activities are described in Table 9-4 below.

TABLE 9-4:
PARTNERSHIPS IN VEGETATION MANAGEMENT

Organization Name	Vegetation Management Activities Performed Pursuant to or Under the Partnership	Objective of the activities Performed Pursuant to or Under the Partnership	PG&E's Role in the Partnership	Anticipated Accomplishments of Partnership Projects During the Three Years of the WMP Cycle
National Arbor Day	Coordinate energy savings tree giveaway within PG&E service territory.	Ensure right trees are planted with energy savings in mind.	Fund and oversee the scheduling of the tree giveaway.	2025-2028: successful communication and implementation of the tree giveaway.
CA Community Colleges	Fund scholarships to Community College Tree or PI Certification Courses. Ensure curriculum for both courses are current with Industry leading expectations and changes.	Encourage participation in Community College Certification Course by individuals who wish to consider Utility Arboriculture tree or inspection work as a career.	Scholarships: Fund a scholarship that is administered by the Community Colleges and Utility Arborist Association (UAA). Provide subject matter experts to review course materials and provide guidance as requested.	2025: Set up PO to Fund Scholarships through 2028. Between 2025 and 2028: Spend $1.7 million on scholarships. Note: Spend rate depends on attendance of classes and need for scholarships.
WCISA/ISA	Work to ensure Vegetation Management Inspectors (VMI) inspection staff has accessibility to take advanced Arboriculture certifications and recertification and access to Continuing education units. (CEU).	Proactively schedule advanced Certification and recertification courses with WCISA throughout the year for PG&E coworkers. Ensure current Arborists have easy access to CEU though their normal course of business.	Help drive the scheduling of the additional courses which would be offered to PG&E internal and external Coworkers. For CEU, work to proactively obtain CEU course codes in advance of trainings or meetings that qualify for CUE hours.	2025: Set up four full Tree Risk Assessment Qualification (TRAQ) course set and refresher courses. Through 2028: Facilitate CEU for benchmarks, roadshows, or meetings as they are scheduled. These actions will continue through 2028.

TABLE 9-4:
PARTNERSHIPS IN VEGETATION MANAGEMENT
(CONTINUED)

Organization Name	Vegetation Management Activities Performed Pursuant to or Under the Partnership	Objective of the activities Performed Pursuant to or Under the Partnership	PG&E's Role in the Partnership	Anticipated Accomplishments of Partnership Projects During the Three Years of the WMP Cycle
CAL FIRE and Fire Safe Councils	Community level engagement through educational presentations, event booths, and tree planting events in partnership with both CAL FIRE & Fire Safe Councils.	Educate PG&E customers, CAL FIRE and Fire Safe Council local offices about safe planting practices near utilities.	Provide the local offices of the CAL FIRE and Fire Safe Council with tools to supply customers with information to make informed decisions when planting near utilities.	Continue to build relationships between central office(s) of the Fire Safe Councils, CAL FIRE, and PG&E's Right Tree, Right Place Program. Provide planting recommendations for situations when assisting communities with plans for wildfire readiness.
Community Organizations (includes Clear Lake Environmental Research Center and Love Tuolumne County)	Support Lake County's Hogback Fuel Crew to increase pay and retention of staff that support mutual aid fire response, projects for ingress-egress improvement, and to protect local hospital and education institutions. Support Love Tuolumne County to build and sustain its first roadside fuels crew, reducing risk to and from powerlines and improving ingress-egress during wildfire events, at lower cost than previous grant-funded County contract crews.	Wildfire capacity building investments in relatively high risk and low-income regions.	Provide grant funding and tactical support as needed.	Increased and sustained fire and fuel capacity in relatively high risk and low income parts of PG&E service area. Identify learnings to inform whether to expand such partnership to other communities. Support fuels treatment and linear roadside brushing in targeted high-value locations. This is not compliance driven work.

TABLE 9-4:
PARTNERSHIPS IN VEGETATION MANAGEMENT
(CONTINUED)

Organization Name	Vegetation Management Activities Performed Pursuant to or Under the Partnership	Objective of the activities Performed Pursuant to or Under the Partnership	PG&E's Role in the Partnership	Anticipated Accomplishments of Partnership Projects During the Three Years of the WMP Cycle
National environmental and forestry non-profits (includes American Forest Foundation, Blue Forest Conservation, and National Forest Foundation)	Support American Forest Foundation (AFF) to create on-the-ground risk reduction in Tuolumne County, while also conducting further development of pathways to scale work in Tuolumne and to other counties in PG&E service area on privately-owned lands. Support Blue Forest Conservation to provide flexible financing for landscape-scale fuels treatments in Plumas and Eldorado National Forests, in combination with relevant water utilities and government grant funding. National Forest Foundation has played a key role in resilience efforts with other peer utilities such as Liberty Utilities, Idaho Power, and Salt River Project. PG&E signed a memorandum of understanding with National Forest Foundation for future collaboration.	Create valuable on-the-ground risk reduction. Identify and/or co-develop scalable pathways to cost-effective wildfire risk reduction through partnership.	Provide grant funding, project down-selection collaboration, and matching funds fundraising and/or tactical support as needed.	Landscape-scale treatments. Development of multi-faceted playbook for cost-effective and large-scale wildfire risk reduction through resilience partnerships. This is not compliance driven work.

TABLE 9-4:
PARTNERSHIPS IN VEGETATION MANAGEMENT
(CONTINUED)

Organization Name	Vegetation Management Activities Performed Pursuant to or Under the Partnership	Objective of the activities Performed Pursuant to or Under the Partnership	PG&E's Role in the Partnership	Anticipated Accomplishments of Partnership Projects During the Three Years of the WMP Cycle
Local Fire and Forestry Districts and Departments (includes Northern Sonoma County Fire District, Garden Valley Fire District, Hogback Fuel Crew in Lake County)	Via grants to non-profit partners, support and collaborate with fire and fuel crews to build capacity and achieve on-the-ground risk reduction.	Create valuable on-the-ground risk reduction.	Provide funding, project down-selection collaboration, and matching funds fundraising and/or tactical support as needed.	Identify learnings to inform whether to expand such partnership to other communities. Fuels treatment and linear roadside brushing in targeted high-value locations. This is not compliance driven work.
Tribal governments and associations (incl. Tribal Ecosystem Restoration Alliance, California Heritage: Indigenous Research Project, and tribal fuel crews such as those for Mooretown and Southern Sierra Mi-Wuk, Nation Tribes)	Support and collaborate with fire and fuel crews to build capacity and achieve on-the-ground risk reduction, such as roadside treatment projects improving ingress and egress on one-way-in and one-way-out roads while reducing risk to and from PG&E assets.	Wildfire capacity building investments, and on-the-ground risk reduction.	Provide grant funding to non-profit partners and provide tactical support as needed.	Learnings to inform whether and how to expand such partnership to other communities. Fuels treatment and linear roadside brushing in targeted high-value locations. This is not compliance driven work.

TABLE 9-4:
PARTNERSHIPS IN VEGETATION MANAGEMENT
(CONTINUED)

Organization Name	Vegetation Management Activities Performed Pursuant to or Under the Partnership	Objective of the activities Performed Pursuant to or Under the Partnership	PG&E's Role in the Partnership	Anticipated Accomplishments of Partnership Projects During the Three Years of the WMP Cycle
Fire Safe Councils and Firewise organizations in targeted locations (incl. Butte, Napa, East Madera, and Mariposa)	Create on-the-ground wildfire risk reduction through fuels treatment.	Create valuable on-the-ground risk reduction. Identify and/or co-develop scalable pathways to cost-effective wildfire risk reduction through partnership.	Funding and tactical support as needed. In the case of Butte County, match-funding for a project in East Oroville which strengthened an application for a much larger CAL FIRE grant, which the Fire Safe Council was since awarded, reducing PG&E and community risk with larger-scale treatment.	Identify learnings to inform whether to expand such partnership to other communities. Fuels treatment and linear roadside brushing in targeted high-value locations. This is not compliance driven work.
Resource Conservation Districts (incl. El Dorado and Nevada Counties)	Create on-the-ground wildfire risk reduction through fuels treatment.	Create valuable on-the-ground risk reduction. Identify and/or co-develop scalable pathways to cost-effective wildfire risk reduction through partnership.	Funding and tactical support as needed.	Learnings to inform whether and how to expand such partnership to other communities. Fuels treatment Sand linear roadside brushing in targeted high-value locations. This is not compliance driven work.

TABLE 9-4:
PARTNERSHIPS IN VEGETATION MANAGEMENT
(CONTINUED)

Organization Name	Vegetation Management Activities Performed Pursuant to or Under the Partnership	Objective of the activities Performed Pursuant to or Under the Partnership	PG&E's Role in the Partnership	Anticipated Accomplishments of Partnership Projects During the Three Years of the WMP Cycle
County (incl. Nevada and Lake Counties)	Provide grants to Counties through EPIC technology demonstration and deployment program to fund pilot community grapple truck and wood disposal programs with the Counties, enabling community wood to be picked up and pooled with operational PG&E wood for large-scale nearby pyrolization into biochar via mobile carbonizers.	Create a new scalable tactic for reducing the cost, environmental impact, and safety of managing excess wood from vegetation projects through partnership.	Grant funding and large-wood volumes and carbonizer utilization contract which reduced county wood disposal costs.	Long-term carbon sequestration, improved wood disposal affordability, and reduced truck miles and associated motor-vehicle risk, criteria pollutants, carbon emissions, road wear-and-tear. Identify learnings to inform whether to expand such partnership to other communities. This is not compliance driven work.

The electrical corporation must also provide a narrative overview of, in order: (1) each current and future vegetation management partnership identified in Table 9-3 and 9-2) vegetation management partnerships it is discontinuing or has discontinued since the last WMP submission and explain why it is discontinuing or has discontinued the vegetation management partnership. Section 9.8.1 provides instructions for the overviews. The sections must be numbered Section 9.8.1 to Section 9.8 (i.e., each vegetation management partnership is detailed in its own section) with the names of the partnering agencies or organizations as the section title.

PG&E is pursuing public-private partnerships as an additional programmatic "tool in the toolbox" for cost-effective wildfire mitigation. Recent research indicates that fuels treatments are highly effective at reducing overall wildfire risk of PG&E's operating environment. For example, one study indicates that large-scale, targeted fuels reductions have the ability to reverse California's catastrophic wildfire trajectory, even when factoring in the dynamic baseline of increasing climate change.[160]

Another report indicates that California would see a net benefit from fuel reduction across nearly four million acres per year, far exceeding the nearly one million acres treated per year today.[161] Early small-scale trials, and benchmarking with other utilities such as the Salt River Project, indicate that utilities can act as a catalyst to enable more critical fuels reduction well beyond utility rights of way to be accomplished to slow any fire spread from wildfires regardless of the ignition source.

Partnerships are attractive because they empower communities, enable non-compliance-driven, risk-reducing fuels treatments to expand outside of utility rights of way, potentially enable customer-relationship building by working with trusted local partners, and create a mechanism for PG&E support. Whereas costs for regulatory-driven work is typically born by utility customers as part of revenue requirement; expenditures on non-regulatory-driven fuel treatment work can leverage other interested parties such as: government, non-profit, landowner, or corporate co-funders, creating even more impact per dollar spent. Early benefit-cost analysis indicates targeted resilience projects to be highly cost-effective. Where used as a match, a dollar of PG&E funding has the potential to be matched by many more external dollars. Depending on permitting requirements, such work can also be completed within a year, thus implying ability to reduce large-scale wildfire risk at a relatively quick pace.

Such public-private partnerships can also create significant co-benefits. The 2020 wildfires were estimated to have wiped out all carbon savings from key state decarbonization measures such as renewable generation and energy efficiency over the previous 20-years.[162] Had fuels in these areas been proactively managed, these carbon emissions would likely have been much less pronounced. Fuels treated in key watersheds also enhances water resilience for California in a context of increasing flood and drought conditions brought about by climate change.

It is worth noting that this public-private partnership tactic to increase resilience focuses most on reducing wildfire consequence risk, instead of reduction in utility ignition likelihood as represented by other mitigations. Thus, efficacy metrics include reduction of fire intensity, minimum travel time, and/or ember cast risk to structures vs. ignition

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160 Brown, P. et al, Environ. Res. Lett, The Potential for Fuel Reduction to Reduce Wildfire Intensity in a Warming California (Jan. 30, 2025), available at: https://iopscience.iop.org/article/10.1088/1748-9326/adab86.

161 Brown, P, Breakthrough Institute, Cost Effectiveness of Large-Scale Fuel Reduction for Wildfire Mitigation in California (Jun. 13, 2024), available at: https://thebreakthrough.org/issues/energy/cost-effectiveness-of-large-scale-fuel-reduction-for-wildfire-mitigation-in-california.

162 Smith, Brad, UCLA Fielding School of Public Health, UCLA-led study finds California's greenhouse gas reductions could be wiped out by 2020 Wildfires (Oct. 17, 2022), available at: https://ph.ucla.edu/news-events/news/ucla-led-study-finds-californias-greenhouse-gas-reductions-could-be-wiped-out-2020#:~:text=A%20new%20analysis%20led%20by,in%20California%20between%202003%2D2019.

likelihood as for most other mitigations, which in this case is held constant during evaluation.

Resilience partnerships to-date have been on a trial basis, to understand the nature of the additional wildfire mitigation alternative. The program will scale based on on-ground results relative to other mitigations, and ability to cost-effectively scale.

9.8.1 Vegetation Management Partnership

9.8.1.1 Overview

In this section, the electrical corporation must provide an overview of the vegetation management partnership including status of the partnership (current, future, or discontinued) and a description of the type of work accomplished through this partnership. This overview must describe where the work accomplished through this partnership takes place (e.g., territory-wide, HFTD only, a specific county, etc.). If available, provide a link to any website associated with the partnership.

9.8.1.2 Partnership History

In this section, the electrical corporation must provide a history of the vegetation management partnership including how long the electrical corporation has been working with the partnering agency/organization, the number of projects completed or in-progress, the scope of completed and in-progress projects (e.g., acres treated, trees planted, etc.), and the electrical corporation's quantitative contribution to the project (e.g. dollars contributed, number of workers provided, number of hours of consultation).

9.8.1.3 Future Projects

In this section, the electrical corporation must provide a description of projects with the partnering agency/organization that are currently planned for the three years of the WMP cycle, have not yet begun, and are fully funded. This description must include the scope of future projects (e.g., acres treated, trees planted, etc.), projected completion years, and the electrical corporation's quantitative contribution to the project (e.g., dollars contributed, number of workers provided, number of hours of consultation).

9.8.1 National Arbor Day

9.8.1.1 National Arbor Day Overview

PG&E holds an ongoing partnership with National Arbor Day (NAD), leveraging their work in tree planting and use of trees to reduce energy use. PG&E partners annually with NAD to distribute power line friendly trees free of charge to the customer. Historically, PG&E utilized NAD in specific regions, rotating yearly through the service territory, but starting in 2023, PG&E utilized NAD for the entire service territory regardless of an area's fire risk designation.

9.8.1.2 National Arbor Day Partnership History

PG&E has been partnering with NAD since 1995, receiving Tree Line USA award every year since that time.

9.8.1.3 National Arbor Day Future Projects

PG&E forecasts to continue the partnership as currently utilized until 2027.

9.8.2 California Community Colleges

9.8.2.1 California Community Colleges Overview

PG&E holds an ongoing partnership with the California Community College system where the organizations worked together to develop two curriculums – a six-week program to train arborists in the basics of climbing, and tree work and a two-week program to train inspectors to inspect power lines for tree conflicts. Once created, PG&E helped fund scholarships to remove financial barriers preventing individuals looking for a career change. This effort took place in the entire PG&E territory and the college system expanded it outside to other California utilities' service territories.

9.8.2.2 California Community Colleges Partnership History

PG&E has provided funding to support the Santa Rosa Junior College Fire Technology Program since 2022. Funding supports scholarships for fire technology students and development of wildfire related curriculum.

9.8.2.3 California Community Colleges Future Projects

PG&E continues its partnership with educational institutions by providing funding and content maintenance support through cooperation with Upskill California and the California Community Colleges; see Section 9.13.1 for more information.

9.8.3 Western Chapter International Society of Arboriculture (WCISA) and International Society of Arboriculture (ISA)

9.8.3.1 WCISA and ISA Overview

PG&E has partnered with the WCISA/ISA to deliver TRAQ training sessions to ensure that PG&E has enough TRAQ Arborists for their program needs. Each year PG&E partners with WCISA to schedule dedicated TRAQ classes and refresher sessions for PG&E employees and coworkers. In many cases, PG&E provides the facilities and meals for the 3-day class, which reduces scheduling challenges and costs for WCISA allowing for more sessions to be offered. This partnership has allowed for an innovative way to track continuing education units, minimizing work for both organizations.

9.8.3.2 WCISA and ISA Partnership History

Since 2022, PG&E and WCISA have been partnering to deliver TRAQ training sessions. Each year, PG&E partners with WCISA to schedule dedicated TRAQ classes and refresher sessions for PG&E employees and coworkers. In many cases, PG&E provides facilities and meals for the 3-day class, reducing scheduling challenges and costs for WCISA.

9.8.3.3 WCISA and ISA Future Projects

PG&E expects to continue the partnership. The frequency and need for TRAQ courses will be dictated by staffing requirements.

9.8.4 CAL FIRE

9.8.4.1 CAL FIRE Overview

PG&E intends to build a service-territory-wide relationship between CAL FIRE and the PG&E Right Tree, Right Place Program. PG&E currently has several individuals from local teams who interact with CAL FIRE, though this engagement is not yet in an organization-wide capacity as related to the Right Tree, Right Place Program.

9.8.4.2 CAL FIRE Partnership History

This partnership is being developed.

9.8.4.3 CAL FIRE Future Projects

PG&E will continue to build relationships between central office(s) of the Fire Safe Councils, CAL FIRE, and PG&E's Right Tree, Right Place Program.

9.8.5 Fire Safe Councils

9.8.5.1 Fire Safe Councils Overview

PG&E intends to build a relationship between local Fire Safe Councils and the PG&E Right Tree, Right Place Program throughout PG&E's service territory. PG&E currently has several individuals participating in local Fire Safe Council Area offices, though this engagement is not yet in an organization wide capacity as related to the Right Tree, Right Place Program.

9.8.5.2 Fire Safe Councils Partnership History

This partnership is currently being developed.

9.8.5.3 Fire Safe Councils Future Projects

PG&E will continue to build relationships between central office(s) of the Fire Safe Councils, CAL FIRE, and PG&E's Right Tree, Right Place Program.

9.8.6 Community Organizations (Incl. Clear Lake Environmental Research Center, and Love Tuolumne County)

9.8.6.1 Community Organizations Overview

These partnerships are designed to expand local capacity for preventative fuels treatment, and in the case of Lake County, also for fire response. This work is taking place within Lake and Tuolumne Counties. Both partnerships are currently active. A description of the Lake County partnership can be found at https://www.theclerc.org/hometown-wildfire-safety-collaborative.

9.8.6.2 Community Organizations Partnership History

PG&E initially partnered with Clear Lake Environmental Research Center (CLERC) in 2023, and with Love Tuolumne County in late 2024.

The grant to CLERC resulted in increased staffing for the Hogback Fuel Crew, two completed non-utility-regulatory-driven fuels treatment projects to-date, one currently ongoing non-utility-regulatory-driven fuels treatment project, the purchase of a new chipper, and the ability for the Hogback Fuel Crew to now be recruited for fire mutual aid. At least 20 acres and three linear miles of on-the-ground fuels have been treated as a result of the project. PG&E provided additional grants in 2024 to fund three night-time enabled dip tanks, and in 2025 a grant for a pilot community grapple and wood disposal program leveraging use of a carbonizer in partnership.

The grant to Love Tuolumne County was completed at the end of 2024. PG&E contributed grant funding to seed the creation of the county fuel crew, with the county pledging to separately raise the rest of needed funds and to support the crew moving forward.

9.8.6.3 Community Organizations Future Projects

PG&E will identify learnings to inform whether to expand such partnerships to other community organizations and regions, and support capacity building, non-utility-regulatory-driven fuels treatment and linear roadside brushing in targeted high value locations.

9.8.7 National Environmental and Forestry Non-Profits (Incl. American Forest Foundation, Blue Forest Conservation, and National Forest Foundation)

9.8.7.1 National Environmental and Forestry Non-Profits Overview

American Forest Foundation and Blue Forest Conservation partnerships are currently active. The partnerships are designed to create valuable on-the-ground risk reduction, and to identify and/or co-develop scalable pathways to cost-effective wildfire risk reduction through partnership. The National Forest Foundation relationship takes the form of a Memorandum of Understanding now, and PG&E is actively exploring opportunities to support each organization’s respective goals. Desired objectives are to create landscape-scale treatments to improve broad-based locational resiliency, and to develop a multi-faceted playbook for cost-effective and large-scale wildfire risk reduction through resilience partnerships. The on-the-ground partnership with American Forest

Foundation has focused in HFTD areas in Tuolumne County. The partnership with Blue Forest Conservation has focused in and around Plumas and Eldorado National Forests.

PG&E's and Blue Forest Conservation's initial partnership accelerating work in the Eldorado National Forest is described in more detail here: https://www.blueforest.org/our-impact/our-projects/upper-mokelumne/.

9.8.7.2 National Environmental and Forestry Non-Profits Partnership History

PG&E's partnership began with American Forest Foundation (AFF) in 2021, when PG&E Foundation supported AFF with two grants sponsoring studies to evaluate the efficacy of wildland-urban interface fuel treatments to reduce average annual loss by insurers. The study indicated wildfire resilience to be a cost-effective wildfire risk reduction solution in the right contexts. With that learning in mind, PG&E provided AFF with a grant in 2023, followed by a separate project-specific grant in 2024. Both grants were focused on reducing wildfire risk in Tuolumne County.

A portion of PG&E's grant was used to treat 20 acres in Tuolumne County.

In 2023, PG&E and Blue Forest Conservation partnered on their first project with a grant for a landscape-scale project in the Upper Mokelumne Watershed near PG&E's Tiger Creek facilities accelerating the deployment in grant funding. In 2024, PG&E made a second grant for that same project and purpose and additionally contributed to seed a large-scale project in Plumas County which is intended to help defend PG&E assets and at-risk communities such as Quincy. The Upper Mokelumne project has so far treated 300 acres. The Plumas project is scheduled to begin in Spring of 2025.

PG&E signed a Memorandum of Understanding with National Forest Foundation (NFF) in 2023. PG&E will continue to explore mutual benefit project opportunities in the future.

9.8.7.3 National Environmental and Forestry Non-Profits Future Projects

PG&E will identify learnings to inform whether to expand such partnership to other service area projects and geographies, and national partners.

9.8.8 Local Fire and Forestry Districts and Departments (Incl. Northern Sonoma County Fire District, Garden Valley Fire District, Hogback Fuel Crew in Lake County)

9.8.8.1 Local Fire and Forestry Districts and Departments Overview

All partnerships are currently active. The partnerships are focused on HFTD locations in Northern Sonoma, El Dorado, and Lake Counties, respectively. Desired outcomes are to create (non-utility-regulatory-driven) fuels treatment and linear roadside brushing in targeted high-value locations reducing on the ground risk, and to create learnings to inform whether and how to expand such partnership to other communities.

9.8.8.2 Local Fire and Forestry Districts and Departments Partnership History

PG&E signed three separate grants with the Northern Sonoma County Fire Foundation in 2024, supporting the Northern Sonoma County Fire Protection District.

- The first grant funded roadside brushing on roads that are important for ingress-egress.
- Following that first project, PG&E provided an additional for non-utility-regulatory-driven fuels treatment and planning project.
- After the second project, Northern Sonoma identified four subsequent projects related to on-the-ground fuels treatment, roadside projects, and community-approved “shovel ready” wildfire resilience projects across contiguous small landowner clusters.
- Following discussions with CAL FIRE and Calpine, PG&E provided an additional grant at the end of 2024 to provide a strategically placed dip tank for additional water availability in the event of needed fire response.

The partnership with Garden Valley Fire District began via a grant to a local non-profit in 2024. The Fire District has used the funding to expand staffing and purchase equipment to create sustainable fire and fuel crew in this high risk and relatively low-income region. The expanded crew will begin work in early 2025.

As noted previously, PG&E also supported the expansion and stabilization of a fire and fuel crew in Lake County with a grant to Clear Lake Environmental Research Center in 2023.

9.8.8.3 Local Fire and Forestry Districts and Departments Future Projects

PG&E will identify learnings to inform whether to expand such partnership to other communities.

9.8.9 Tribal Governments and Associations (Incl. Tribal Ecosystem Restoration Alliance, California Heritage Indigenous Research Project, and Tribal Fuel Crews Such as Those for Mooretown and Southern Sierra Mi-Wuk, Nation Tribes)

9.8.9.1 Tribal Governments and Associations Overview

All Tribal Governments partnerships are currently active. Funding to build out and sustain fuel crews, and targeted fuels treatments, is focused in HFTD areas in Lake, Nevada, Butte, and Mariposa Counties, respectively. The partnerships are looking at expansion in other areas for cost-effective risk reduction with existing partners and with other tribal entities to build out and sustain additional fuel crew capacity in other locations, and to execute fuels treatment and linear roadside brushing in targeted high value locations to reduce wildfire risk.

9.8.9.2 Tribal Governments and Associations Partnership History

PG&E Foundation funding supported establishment of the Tribal Ecosystem Restoration Alliance (TERA) several years ago. TERA has since proven successful at securing contracts for fuels treatment on federal and private lands but needed support to develop support functions. At the end of 2024, PG&E provided TERA a capacity-building grant to help the organization build back-office functions, in turn accelerating fuels reduction work moving forward.

California Heritage Indigenous Research Project (CHIRP) is a tribal organization affiliated with the Nevada County Rancheria – Nisenan Tribe in Nevada County. PG&E provided CHIRP a grant in Fall 2024 which enabled high quality roadside fuels treatment on roads important for ingress and egress adjacent to powerlines.

PG&E provided two contracts to the Butte County Fire Safe Council for roadside clearing, which was executed by a Mooretown tribal fuel crew. Once completed, the project will have treated three linear miles of roadside treatment on challenging roads for ingress and egress, which typically have adjacent powerlines.

PG&E provided the Mariposa Fire Safe Council a grant at the end of 2024 to conduct roadside treatments along roads which are challenging for ingress and egress with adjacent powerlines in Mariposa County. PG&E's grant funding was highlighted by the Fire Safe Council as serving as an effective catalyst for desired buildup of this Tribal fuel crew's capacity. The work is expected to be completed in Spring 2025 with the treatment of three linear miles.

9.8.9.3 Tribal Governments and Associations Future Projects

PG&E will leverage learnings to inform whether and how to expand such partnership to other communities.

9.8.10 Fire Safe Councils and Firewise Organizations in Targeted Locations (Incl. Butte, Napa, East Madera, and Mariposa)

9.8.10.1 Fire Safe Councils and Firewise Organizations in Targeted Locations Overview

All partnerships are currently active. Local-organization-driven fuel treatment projects are focused in HFTD locations in Butte, Napa, Madera, and Mariposa Counties, respectively to reduce risk to their respective communities. Desired outcomes are to create learnings informing whether and how to expand such partnership to other communities, and to assist these local organizations in their execution of fuels treatment and linear roadside brushing in targeted high-value locations reducing wildfire risk.

9.8.10.2 Fire Safe Councils and Firewise Organizations in Targeted Locations Partnership History

After conducting a technology pilot held on PG&E property in 2023, PG&E and Butte County Fire Safe Council (FSC) identified an area southwest of Oroville Dam for a large non-utility-regulatory-driven fuels management project for defense of the surrounding community. Butte County FSC gathered a larger stakeholder group including the California Department of Water Resources to submit a grant application for CAL FIRE funding to treat 2,416 acres. PG&E committed matching the funding treatment of relevant PG&E lands. CAL FIRE approved the grant application. However, before the work began, the Thompson Fire burned a significant portion of the scoped area. The grant has since been awarded, and PG&E will be providing the matching funding when needed. Project scope will now be a blend of fuels treatment and post-fire recovery. Work is to begin after California Environmental Quality Act permitting is secured.

As noted previously, PG&E also provided two additional grants to Butte County FSC in Fall and Winter 2024 for roadside treatment.

PG&E provided a grant to Napa Firewise at the end of 2024 to support roadside brushing along a fuel break, to fund "enhanced resilience sites," and to supplement funding provided by PG&E in 2023 funding to enable operationalization of two dip tanks.

PG&E provided grants to Mariposa and East Madera Fire Safe Councils for roadside projects to treat fuels along roads important for ingress and egress near PG&E assets. The grants were provided at the end of 2024. Once completed, the projects will result in three and four linear miles of treatment in Mariposa and Madera Counties, respectively.

9.8.10.3 Fire Safe Councils and Firewise Organizations in Targeted Locations Future Projects

PG&E will leverage learnings to inform whether and how to expand such partnership to other communities.

9.8.11 Resource Conservation Districts (Incl. El Dorado and Nevada Counties)

9.8.11.1 Resource Conservation Districts Overview

All partnerships are currently active. Conservation-district-driven fuel treatment projects are focused in El Dorado and Nevada Counties, respectively. Desired outcomes are to create learnings informing whether and how to expand such partnership to other communities, and to support their fuels treatment and linear roadside brushing projects in targeted high-value locations reducing wildfire risk.

9.8.11.2 Resource Conservation Districts Partnership History

PG&E provided El Dorado Resource Conservation District (RCD) with a grant at the end of 2024 to complement a larger CAL FIRE grant to fund treatment around Spanish Flats and Traverse Creek. Work has not yet started, but the project is anticipated to result in 70 acres of incremental treatment.

PG&E also provided a grant to Nevada County Resource Conservation District at the end of 2024 to support roadside brushing along an important road for ingress and egress near PG&E assets. Work has not yet started. The project will result in two linear miles treated upon completion.

9.8.11.3 Resource Conservation Districts Future Projects

PG&E will leverage learnings to inform whether and how to expand such partnership to other communities.

9.8.12 County (Incl. Nevada and Lake Counties)

9.8.12.1 County Overview

All partnerships are currently active. Wood disposal biochar partnership sites are located respectively in Grass Valley, Nevada County, and Middletown, Lake County. Desired outcomes are to improve wood disposal affordability, create long-term carbon sequestration, and reduce truck miles and associated motor-vehicle risk, criteria pollutants, carbon emissions, and road wear-and-tear, and also to generate learnings to inform whether and how to expand such partnership to other communities. More details on the Nevada County project can be found at the following website: https://www.nevadacountyca.gov/4069/Biomass-Pilot-Project. More details on the Lake County project are available here: https://www.theclerc.org/hometown-wildfire-safety-collaborative

9.8.12.2 County Partnership History

A demonstration was conducted in 2022 utilizing a Tigercat Carbonizer to identify economic benefits of disposing of large volumes of wood.

In 2024, PG&E provided grants to Nevada County and to Clear Lake Environmental Research Center (CLERC) in Lake County, through EPIC program funding to explore a new partnership model for cost-effective, large-scale, and ad hoc wood management solutions. PG&E provided grants to both Counties to trial this partnership model as stand-in for future potential upfront budgeted funding. Counties in turn played key roles in identifying and enabling the first carbonizer sites in each County. Both Nevada County and Lake County sites are planned to be operational in early 2025 and will be operating for several weeks until initial wood stockpiles have been exhausted. If successful, the operational partnership could serve as a model for future partnerships between organizations seeking cost-effective and carbon sequestering wood disposal options.

9.8.12.3 County Future Projects

PG&E will leverage its experience with these partnerships to inform whether and how to expand such partnerships to other communities. PG&E has no current commitments for public-private partnerships and mitigations other than the partnerships described above.

9.9 Activities Based on Weather Conditions

Tracking ID: N/A

9.9.1 Overview

In this section, the electrical corporation must provide an overview of planning and execution of operational changes to address wildfire risk associated with weather conditions such as pruning or removal, executed based on and in advance of a Red Flag Warning or other forecasted weather conditions that indicates an elevated fire threat in terms of ignition likelihood and wildfire potential.

PG&E may perform reactive inspections and tree work to address high wildfire risk conditions to supplement PG&E's proactive VM inspection programs. PG&E currently executes operational changes to address wildfire risk associated with weather conditions in two situations: Public Safety Power Shutoff (PSPS) preparation and forecasted adverse weather conditions.

PSPS Preparation: During peak wildfire conditions in which a PSPS event is being planned, high priority vegetation work is completed in advance of the materializing weather conditions. The activities enable PG&E to potentially reduce the scope of the PSPS event and minimize potential vegetation contact.

In advance of a PSPS event, outstanding tree work located within the scope of a potential PSPS event is prioritized for execution. Barring external factors, this typically includes prioritizing Distribution P1 and P2 work, and Transmission Priority HN-I and HN-U work located within the scope of that PSPS event. Distribution priority level tags and Transmission urgency levels are defined in Section 9.3.3. See Section 11 on Emergency Preparedness, Collaboration, and Community Outreach for additional information.

Forecasted Adverse Weather Conditions: When weather is elevated, further vegetation patrol and tree work may be conducted to reduce the potential impact of vegetation contact on electric facilities. The scope of weather-driven activities can be driven proactively based on historical analysis on frequently impacted locations or responsively based on in-year weather indications and hotspots.

For fire precautions and restrictions due to hazardous fire potential conditions, EMER-4102S also limits tree work activities due to the potential of work producing a spark, fire or flame.

9.9.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used for activities based on weather conditions.

The following documents describe key procedures for Activities Based on Weather Conditions:[163]

- Tsunami Annex, EMER-3104M Revision 4, Effective Date 09/26/2024;
- Wildfire Annex, EMER-3105M, Version 5, Effective date 03/29/2024;
- Public Safety Power Shutoff Annex, EMER-3106M – Public Safety Power Shutoff Version 9, Effective date 07/31/2024;
- Extreme Weather Annex, EMER-3108M Revision 3, Effective 11/14/2024; and
- Preventing and Mitigating Fires While Performing PG&E Work, EMER-4102S Revision 0, Effective Date 03/01/2024.

9.9.3 Scheduling

In this section, the electrical corporation must describe how activities based on weather conditions are scheduled (or triggered). This must include how the schedule is affected by HFTD tier or other risk designation.

In normal operating conditions, the activities will be scheduled consistent with Section 9.3.3. Outside of normal operating conditions, such as when emergency centers are activated, scheduling is based on the direction from the emergency centers. Our activities based on weather conditions are not affected by HFTD tier, because they are case-specific and dependent entirely upon the guidance from our emergency operations centers.

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[163] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

9.9.4 Updates

In this section, the electrical corporation must describe changes to its activities based on weather conditions since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to activities based on weather conditions and the timeline for implementation.

There are no updates to PG&E's activities based on weather conditions since the last WMP submission.

9.10 Post-Fire Service Restoration

Tracking ID: N/A

9.10.1 Overview

In this section, the electrical corporation must provide an overview of vegetation management activities during post-fire service restoration.

After a wildfire occurs, PG&E VM is responsible for mitigating vegetation that is hazardous to restoring and operating PG&E's facilities. Each fire event is different in location, intensity, and severity, as well as impacted assets, vegetation density, vegetation type, response required, and therefore, the plan to restore service is likely to be different for each fire event. Because each wildfire event is unique, VM's response must also be unique. VM's response is also based on collaboration with key stakeholders within the Incident Command System (ICS) who help develop a scope of work for VM that aligns with PG&E organizational objectives.

9.10.2 Procedures

In this section, the electrical corporation must list applicable electrical corporation procedure(s), including the version(s) and effective date(s), used for post-fire service restoration vegetation management.

The following documents describe key procedures for post-fire service restoration:[164]

- Vegetation Management Post Wildfire Response, TD-7114S Revision 1, Effective date 07/15/2024; and
- Vegetation Management Post Wildfire, TD-7114P-01 Revision 0, Effective date 08/06/2024.

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[164] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

9.10.3 Scheduling

In this section, the electrical corporation must describe how post-fire service restoration vegetation management are scheduled (or triggered). This must include how the schedule is affected by HFTD tier or other risk designation.

VM post-fire response happens in two phases: the Initial Phase and the Extended Phase.

The Initial Phase is the initial response where VM focuses on mitigating vegetation that is an imminent threat to PG&E facilities or worker safety. Additional work is often necessary to support work crews, such as clearing and removing vegetation.

The Extended Phase is focused on rebuilding the electric system to restore service to all customers who had service before the fire. This includes vegetation work not addressed during the Initial Phase that may still pose a threat to existing or rebuilt facilities but was not immediate in nature. Also in this phase, additional customers begin to repopulate within the affected areas. As new facilities are constructed, VM work is often needed to support the long-term rebuild efforts.

9.10.4 Updates

In this section, the electrical corporation must describe changes to post-fire service

restoration vegetation management since the last WMP submission and a brief explanation as to why those changes were made. Discuss any planned improvements or updates to post-fire service restoration and the timeline for implementation.

The Vegetation Management Post Wildfire procedure (TD-7114P-01) was drafted in 2024 and published to provide procedural guidance during post-wildfire operations. No specific improvements or updates are currently planned; however, procedural guidance may be reviewed and updated as part of PG&E's standard procedure review process.

9.11 Quality Assurance and Quality Control

Tracking ID: VM-08D; VM-08T; VM-22D; VM-22P; VM-22T

9.11.1 Overview, Objectives, and Targets

In this section, the electrical corporation must provide an overview of each of its QA and QC programs for vegetation management. This overview must include the following for each program:

- *Initiative/activity being audited (each initiative/activity name must correspond to an initiative/activity described in Sections 9.2 through 9.9);*
- *Tracking ID from Table 9-1 or 9-2;*
- *Quality program type (QA or QC); and*
- *Objective of the quality program.*

The electrical corporation must also provide the following tabular information for each QA and QC program:

- *Initiative/activity being audited (each initiative/activity name must correspond to an initiative/activity described in Sections 9.2 through 9.9);*
- *Population/sample unit;*
- *Population[165] size for each audited initiative/activity for each year of the 3-year WMP cycle;*
- *Sample size for each audited initiative/activity for each year of the 3-year WMP cycle;*
- *Percent of sample in the HFTD for each audited initiative/activity for each year of the 3-year WMP cycle;*
- *Confidence level and Margin of Error (MOE); and*
- *Target pass rate for each audited initiative/activity for each year of the 3-year WMP cycle.*

[165] *In this section, a population may be the number of circuit miles inspected, the number of poles cleared, trees prescribed work, etc.*

PG&E's VM Quality Management (QM) System leverages two quality initiatives to verify operational execution of vegetation management procedures. These initiatives include VM Quality Assurance (VMQA) and VM Quality Control (VMQC). VMQA programs ensure a representative sample of PG&E overhead facilities meet regulatory compliance by conducting field reviews, independent of VM inspection and tree work schedules. VMQC programs ensure recently completed inspections and tree work meet quality standards. Inspections and tree work are assessed against PG&E's standards and procedures and PRC sections 4292 and 4293, GO 95, Rule 35 and FAC-003-5.

VMQA and VMQC program objectives are summarized in Table 9-5 below.

TABLE 9-5:
VEGETATION MANAGEMENT QA AND QC PROGRAM OBJECTIVES

Initiative/ Activity Being Audited	Tracking ID	Quality Program Type	Objective of the Quality Program
VM Operations Distribution	VM-08D	QA	Complete the annual Quality Assurance Audit Plan to calculate and report the pass rate of VM Operations Program locations.
VM Operations Transmission	VM-08T	QA	Complete the annual Quality Assurance Audit Plan to calculate and report the pass rate of VM Operations Program locations.
VM Operations Distribution	VM22D	QC	Complete the annual Quality Control Audit Plan to determine the pass rate of VM Operations Program locations.
VM Operations Pole Clearing[a]	VM-22P	QC	Complete the annual Quality Control Audit Plan to determine the pass rate of VM Operations Program locations.
VM Operations Transmission	VM-22T	QC	Complete the annual Quality Control Audit Plan to determine the pass rate of VM Operations Program locations.

(a) We apply a consistent sampling ratio for both risk and compliance poles in our QC methodology. See 2026-2028 WMP Revision Notice Response R0, Critical Issue RN-PGE-26-10 for additional information.

VMQA and VMQC program targets are summarized in Table 9-6 below.

- Reporting: PG&E will use the targets in Table 9-6 below for quarterly compliance reporting including the QDR, Quarterly Notification (QN), and the Annual Report on Compliance (ARC). We note that throughout this 2026-2028 WMP, we discuss current plans for wildfire-related activities beyond the targets in Table 9-6. The timing and scope of these additional activities may change. We will not be reporting on these activities in our QDR, QN, or ARC because they are not defined targets, but are descriptions of plans and activities in our 2026-2028 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All targets in this WMP are subject to External Factors. External Factors in this context represent reasonable circumstances which may impact execution against targets including, but not limited to, physical conditions, environmental delays, landowner or customer refusals or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, wildfires, exceptions or exemptions to regulatory/statutory requirements, and other safety considerations.

- Utility Initiative Tracking IDs (Tracking IDs): We are including Tracking IDs in each section that has associated targets. Table 9-6 displays the Tracking IDs we are implementing to tie the targets to the narratives and targets in the WMP. The Tracking IDs will also be used for reporting in the QDR.

- High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Zone Areas: Unless stated otherwise, all initiatives described in Table 9-6 either involve work or audits on units or equipment located in, traversing, or energizing HFTD, HFRA, or Buffer Zone areas.[166]

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166 Updated based on Substantive Errata filing on April 18, 2025 in accordance with Energy Safety's issuance of Revision Notice at 21.

TABLE 9-6:
VEGETATION MANAGEMENT QA AND QC ACTIVITY

Initiative/Activity Being Audited	Population/ Sample Unit	2026: Population Size(d)	2026: Sample Size	2026: % of Sample in HFTD	2027: Population Size(d)	2027: Sample Size	2027: % of Sample in HFTD	2028: Population Size d)	2028: Sample Size	2028: % of Sample in HFTD	Confidence level/MOE	2026: Pass Rate Target	2027: Pass Rate Target	2028: Pass Rate Target
Vegetation Management Quality Assurance – Distribution Routine (VM-08D)	Miles(a)	25,748(e)	500	100%	25,748(e)	500	100%	25,748(e)	500	100%	95/3.25%	97%	97%	97%
Vegetation Management Quality Assurance – Transmission Routine (VM-08T)	Miles(a)	5,624(e)	200	100%	5,624(e)	200	100%	5,624(e)	200	100%	95/3.25%	97%	97%	97%
Vegetation Management Quality Control – Distribution Routine (VM-22D)	Spans(b)	551,643(e)	80,000	100%	551,643(e)	80,000	100%	551,643(e)	80,000	100%	99/5%	95%	95%	95%
Vegetation Management Quality Control – Pole Clearing (VM-22P)	Poles(b)	70,000	11,500	100%	70,000	11,500	100%	70,000	11,500	100%	99/5%	95%	95%	95%
Vegetation Management Quality Control – Transmission Routine (VM-22T)	Spans(b)	50,669	13,500	100%	50,669	13,500	100%	50,669	13,500	100%	99/5%	95%	95%	95%

(a) Overhead circuit miles in HFTD/HFRA

(b) VMQC Distribution/Transmission/Pole Population is comprised of the overhead span inspected or subject pole locations that have been cleared by VM Operations in HFTD/HFRA.

(c) The VC Pole Clearing Procedure considers both risk and compliance poles as subject; both subsets are incorporated into the sample population. Please Critical Issue RN-PGE-26-10 in 2026-2028 WMP Revision Notice Response R0 for additional information.

(d) Population Size subject to change for 2026-2028 due to construction activities and revisions to fire district/risk area boundaries.

(e) Updated based on Substantive Errata filed on April 18, 2025 in accordance with Energy Safety's issuance of Revision Notice at 21.

VM Quality Assurance

The VMQA team performs audits of VM Distribution, Transmission, and Vegetation Control work to confirm compliance with state and federal compliance requirements (including GO 95 Rule 35 and PRC Sections 4292 and 4293, FAC-003-5). These QA audits are conducted independent of timing of inspection and tree work projects.

The audit mileage is based on calculating the total number of line miles within the audit area and then compiling a sample with the parameters of 95 percent confidence, 99 percent estimated level of compliance, and 3.25 percent margin of error. See VM-08D; VM-08T in Table 9-6 for more information.

VM Quality Control (VMQC)

The VMQC activity is to determine whether the VM work is meeting operational standards and procedures. Through this program, PG&E performs field reviews after VM Operations has completed their inspections and/or tree work to verify the applicable procedural scope has been met.

The annual volumetric minimum sample sizes for QC are determined using a 95 percent confidence level, 5 percent margin of error sampling calculation. In HFTD/HFRA,[167] VMQC samples are sourced from completed VM inspected and/or tree work locations. See VM-22D; VM-22P; VM-22T in Table 9-6 for more information.

9.11.2 QA/QC Procedures

In this section, the electrical corporation must list the applicable procedure(s), including the version(s) and effective date(s), used for each vegetation management QA and QC program listed in Table 9-5.

The following documents describe key procedures for Quality Assurance and Quality Control:[168]

VMQA:

- Asset Distribution & Transmission BPD, MID:0009 Revision 2, Effective date 01/27/2025;
- QAVM-Asset Post-Audit Corrective Actions, SW-0038 Revision 0, Effective date 03/21/2024; and
- QAVM-Asset Transmission Audit of Vegetation Management Activities Revision 0, SW-0045, Effective date 08/14/2024.

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167 Updated based on Non-Substantive Errata filing on May 16, 2025 in accordance with Energy Safety's issuance of Revision Notice at 21.

168 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

VMQC:

- Quality Control Vegetation Management Business Process Document, 0002 Revision 2, Effective date 04/10/2024;
- Quality Control Vegetation Management for Routine Electric Distribution, SW-0003 Revision 3, Effective date 05/31/24;
- Quality Control Vegetation Management for Routine Electric Transmission, SW-0006 Revision 2, Effective date: 04/02/2024; and
- Quality Control Vegetation Management for Vegetation Control Pole Clearing, WS-0004 Revision 4, Effective date 07/03/2024.

9.11.3 Sample Sizes

In this section, the electrical corporation must describe how it determines the sample for each QA and QC program listed in Table 9-5. This must include how HFTD tier or other risk designations affect the sampling plan, and how the electrical corporation ensures samples are representative of the population.

VMQA and VMQC audit locations are sampled from HFTD/HFRA[169] areas.

For VMQA and VMQC, the following formula is used to determine sampling:

SAMPLING FOR PROPORTIONS

$$n = sample \quad size = \frac{\dfrac{z^2 * p * (1-p)}{d^2}}{1 + \dfrac{1}{N} * \left[\dfrac{z^2 * p * (1-p)}{d^2} - 1 \right]}$$

$$z = level \quad of \quad confidence \quad (1.645 - 90\%) \quad (1.960 - 95\%) \quad (2.576 - 99\%)$$
$$p = a \quad prior \quad estimate \quad of \quad the \quad proportion$$
$$d = actual \ error \ (\pm 5\%, \pm 8\%, \pm 12\%, etc.)$$
$$N = population \quad size$$

From Cochran, Sampling Techniques, 3rd Edition, Wiley

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169 Updated based on Non-Substantive Errata filing on May 16, 2025 in accordance with Energy Safety's issuance of Revision Notice at 21.

9.11.4 Pass Rate Calculation

In this section, the electrical corporation must describe how it calculates pass rates. This description must include:

- *The sample unit that generates the pass rate for each QA and QC program (e.g., for pole clearing, the sample unit that generates the pass rate may be a single pole that passes or fails a QC audit); and*
- *The pass and failure criteria for each program listed in Table 9-5. List each criterion and discuss any weighted contributions to the pass rate.*

VMQA and VMQC pass rates are calculated as described below.

<u>VMQA Distribution and Transmission</u>:

- **Pass Rate** = (Total Grow-In Trees Inspected – Total Grow-In Trees Observed Not in Compliance*)/Total Grow-In Trees Inspected x 100
- **Total Trees Passed** = Total Grow-In Trees Inspected – Total Grow-In Trees Not in Compliance*

  *Depending on audit type, not compliant with either GO 95 Rule 35, PRC 4293, or (transmission only) FAC-003-5.

<u>VMQC Pole Clearing:</u>

- **Poles Passed** = Poles Inspected – Pole Failed

<u>VMQC Distribution</u>:

- **Distribution Pass Rate** = (Total Trees Inspected –Total Trees Failed)/ Total Trees Inspected x 100
- **Total Trees Passed** = Total Trees Inspected –Total Trees Failed

<u>VMQC Transmission:</u>

- **Transmission Pass Rate** = (Total Trees Inspected – Total Trees Failed)/ Total Trees Inspected x 100
- **Transmission Trees Passed** = Transmission Trees Inspected - Transmission Trees Failed

9.11.5 Other Metrics

In this section, the electrical corporation must list and describe the metrics used by the electrical corporation, other than pass rate, to evaluate the effectiveness of its vegetation management and inspection activities (programs) and procedures (e.g., find rate, rework rate, outage rate within six months of inspection attributed to vegetation contact, etc.)

VMQA and VMQC assessment results provide confirmation that the VM Operations workforce is achieving the intended deliverables in alignment with PG&E’s standards, procedures, and regulatory compliance. In addition, quality assessments identify deviations from the applicable standards and procedures. Regulatory non-compliant findings are reported by quality to VM Operations promptly, as an extra layer of defense.

Quality results are utilized to pinpoint poor performance at an individual and/or company level. Negative work quality trends inform effective corrective actions and preventative measures.

QM collaborates with VM Operations during quality learning forums to compare quality results from the Vegetation Operation Inspectors and other work execution quality.

9.11.6 Documentation of Findings

In this section, the electrical corporation must describe how it documents its QA and QC findings and incorporates lessons learned from those findings into corrective actions, trainings, and procedures.

VMQA and VMQC data is captured in a system of record, which include operational findings, points of cause, and where appropriate, individual/company performing the work.

VMQA documents corrective actions identified during a distribution and transmission audit in the corrective action program system.

Quality learning forums are conducted by QM leaders in collaboration with local VM Operations to review findings and trends. During these forums, opportunities for improvement are discussed and corrective actions are established, which may include: training updates, procedural modifications, and/or contractor leadership meetings.

9.11.7 Changes to QA/QC Since Last WMP and Planned Improvements

In this section, the electrical corporation must describe:

- *A list of changes the electrical corporation made to its QA and QC procedure(s) since its last WMP submission;*
- *Justification for each of the changes including references to lessons learned as applicable; and*
- *A list of planned future improvements and/or updates to QA and QC procedure(s) including a timeline for implementation.*

Since the prior WMP submission, PG&E's QM has removed the Field Quality Control (FQC) program. The program was originally developed to conduct in-field knowledge and training checks. Because VM Operations has established ongoing knowledge checks as part of its operations oversight organization, the FQC program within QM was determined to be redundant.

The portion of Target VM-08 related to QA of Pole Clearing is discontinued because QA pass rates have consistently performed well, and QC more effectively targets ignition sources. QC Pole Clearing will continue to be performed in accordance with VM-22P.

9.12 Work Orders

Tracking ID: N/A

In this section, the electrical corporation must provide an overview of how it manages its work orders resulting from vegetation management inspections that prescribe vegetation management activities. This overview must include the following under these headers:

9.12.1 Priority Assignment

In this section, the electrical corporation must describe how work orders are assigned priority, including the activity timeline for each priority level/group.

Vegetation Management activities are performed within electronic work orders assigned to contractors to track and document completed field work. All trees identified by VM inspectors during inspections as needing trimming or removal are evaluated and prioritized based on PG&E standards to comply with applicable regulations.

Work orders are generated throughout the year via the inspection process. Those work orders that have tree work executed are closed. At any point in time, open work orders represent vegetation points pending work (trim or removal), on hold due to constraints, pending invoicing, or in-progress.

PG&E applies time requirements for its priority conditions once tree work has been prescribed by an inspection program unless constrained, as described in Section 9.3.3.

9.12.2 Backlog Elimination

In this section, the electrical corporation must describe the plan for eliminating work order backlogs (i.e., open work orders that have passed activity timelines), if applicable.

Work order backlogs are created when open work order deadlines have passed target timelines. Outstanding tree work may have passed target timelines if the vegetation point is constrained by: environmental permitting, encroachment permitting, customer interference, biological, active wildfire, weather conditions, or other constraints. VM monitors constraints and seeks opportunities to continuously improve resolution processes.

9.12.3 Trends

In this section, the electrical corporation must describe trends with respect to open work orders and:

An aging report for work orders past due (i.e., work orders that were not completed within the electrical corporation's assigned activity timelines per priority level/group described in Section 9.11.1).

Past-due VM work orders categorized by age and HFTD tier are summarized in Table 9-7 below. Past-due VM work orders categorized by age and priority levels are summarized in Table 9-8 below. These categorizations and priority metrics are based on PG&E standards and procedures. PG&E manages the completion of aging work orders through reporting and the operating review structure.

TABLE 9-7:
NUMBER OF PAST DUE VEGETATION MANAGEMENT WORK ORDERS CATEGORIZED BY AGE AND HFTD TIER

HTFD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
Non-HFTD	3	–	–	–
HFTD Tier 2	–	–	–	–
HFTD Tier 3	–	–	–	–

Notes:

- Totals are based on number of days past due according to PG&E standards and procedures as of 12/31/2024.
- Constrained units are excluded.
- The work is complete for the three trees listed above.

TABLE 9-8:
NUMBER OF PAST DUE VEGETATION MANAGEMENT WORK ORDERS CATEGORIZED BY AGE AND PRIORITY LEVELS

Priority Level	0-30 Days	31-90 Days	91-180 Days	181+ Days
Priority 1	–	–	–	–
Priority 2	3	–	–	–
Priority 3	–	–	–	–

Notes:

- Totals are based on number of days past due according to PG&E standards and procedures as of 12/31/2024.
- Constrained units are excluded.
- Priority 1 and Priority 2 categories include trees identified as P1 or P2 based on the Priority Tag Procedure and HN-I or HN-U based on the Transmission VM Imminent Threat and Hazard Notification Procedure.
- Priority 3 includes Distribution routine, non-priority trees. The 365-day standard timeline applies to Distribution routine, non-priority work, as per procedure TD-7102S.
- The work is complete for the three trees listed above.

9.13 Workforce Planning

Tracking ID: VM-24

In this section, the electrical corporation must provide an overview of vegetation management and inspections personnel.

The electrical corporation must:

- *List all worker titles relevant to vegetation management and inspections including, but not limited to, titles related to inspecting, auditing, and tree crews; and*
- *List and describe minimum qualifications for each worker title with an emphasis on qualifications relevant to vegetation management:*
  - *The electrical corporation must note if workers with title hold any certifications, such as being an International Society of Arboriculture Certified Arborist or a California-licensed Registered Professional Forester.*

PG&E will continue to report annually on our execution of planned recruitment, retention, and training of vegetation management and inspections personnel and partnerships. See VM-24 in Table 9-1 in Section 9.1.1 for more details. See Revision Notice Response to Critical Issue RN-PGE-26-08 for additional information.

Vegetation Management Qualifications and Training is summarized in Table 9-9 below.

TABLE 9-9:
VEGETATION MANAGEMENT QUALIFICATIONS AND TRAINING

Worker Title	Minimum Qualifications for Target Role	Applicable Certifications	# of Electrical Corporation Employees With Min Quals	# of Electrical Corporation Employees with Special Certifications	# of Contracted Employees With Min Quals	# of Contractor Employees With Applicable Certifications	Total # of Employees	Reference to Electrical Corporation Training/ Qualification Programs
VMI and Senior Vegetation Management Inspectors (SVMI)	<u>For VMI</u>: High School diploma or General Educational Development Test (GED), AND Required to maintain a Class C driver's license AND must meet one of the experience levels below: • Experience/education requirements (must meet one): • 1 year of related arboricultural experience, OR • ISA Certified Arborist, OR • 2-year or 4-year college degree in a related field, AND • Approval by PG&E Representative <u>For SVMI</u>: High School diploma or GED, AND Required to maintain a Class C driver's license AND must meet one of the experience levels below: • 5 years of experience as a tree crew climber/tree crew foreman with at least 2 years of line clearance certification, OR • 5 years of experience as a Vegetation Management Inspector and Certified Arborist, OR • 5 years of experience as a Registered Professional Forester, OR • 5 years of experience as a Utility Inspector or higher classification with at least 1 year of vegetation management experience, OR • 4 years of Military Service with honorable discharge and at least 1 year additional year of vegetation management inspection experience, AND • Approval by PG&E Representative.	• Certified Arborist • Registered Professional Forester	300	• Certified Arborist – 130 • Registered Professional Forester – 1 *Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	1,007	• Certified Arborist – 409 • Registered Professional Forester – 2 *Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	1,291	VMI Basics
Field Supervisor (FS)	Minimum of 5 years' experience in line clearance tree work and have been a qualified line clearance tree worker. • Equivalent experience may be acceptable at the discretion of the Vegetation Program Manager. The FS shall be familiar with the Contractor's work practices, PG&E's Specification, and all applicable legal and regulatory requirements relating to the Work required.	N/A	0	0	195	N/A	195	N/A – Tree Work Training is not provided by PG&E

TABLE 9-9:
VEGETATION MANAGEMENT QUALIFICATIONS AND TRAINING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Applicable Certifications	# of Electrical Corporation Employees With Min Quals	# of Electrical Corporation Employees with Special Certifications	# of Contracted Employees With Min Quals	# of Contractor Employees With Applicable Certifications	Total # of Employees	Reference to Electrical Corporation Training/ Qualification Programs
Foreman (FM)	A minimum of 18 months experience in line clearance tree work and is a qualified line clearance tree worker. Capable of climbing and possess a valid certification document issued by Contractor. Equivalent experience may be acceptable at the discretion of the Vegetation Program Manager. The FM shall be familiar with the Contractor's work practices, PG&E's Specification, and all applicable legal and regulatory requirements relating to line clearance work and fire prevention related to the Work and use this knowledge to direct his/her crew(s).	N/A	0	0	1,353	N/A	1,353	N/A – Tree Work Training is not provided by PG&E
Patrolman (PT)	A PT shall, by reason of his or her training and/or experience, and demonstrated through his or her performance, be familiar with the requirements of line clearance tree pruning and possess good customer contact skills	N/A	0	0	0	N/A	0	N/A – Tree Work Training is not provided by PG&E.
Journeyman Tree Trimmer/Climber (CL)	A minimum of 18 months experience in line clearance tree work. Possess a valid certification document issued by Contractor. Met the state approved training requirements to work within 10 feet of energized conductors. Shall be familiar with the Contractor's work practices and requirements related to line clearance work.	N/A	0	0	613	N/A	613	N/A – Tree Work Training is not provided by PG&E
Apprentice Trimmer/Climber (AC)	A minimum of 3 months experience as a groundman. An AC shall be defined as a tree worker undergoing on- the-job training and shall have demonstrated the ability to perform his or her duties safely and in accordance with applicable state and federal regulations	N/A	0	0	818	N/A	818	N/A – Tree Work Training is not provided by PG&E
Groundman/Flagman (GM)	A GM shall be defined as a crew member other than a PT, CL or AC working under the direct supervision of the FM.	N/A	0	0	525	N/A	525	N/A – Tree Work Training is not provided by PG&E
Vegetation Control Technician (VC Tech)	Vegetation control experience or other related work, including relevant pesticide and related licenses and certificates. Preferred – ISA Certified Arborist, ISA Certified Tree Worker, and/or TCIA Certified Tree Care Safety Professional.	N/A	0	0	393	N/A	393	VEGM-0302 and VEGM-0303
Brush Crew Foreman	18 months related experience. Electrical groundman or lineman experience preferred or any equivalent combination of experience and certified training that provides the required knowledge, skills, and abilities. High school graduate, or its equivalent required	N/A	0	0	53	N/A	53	N/A – Tree Work Training is not provided by PG&E.

TABLE 9-9:
VEGETATION MANAGEMENT QUALIFICATIONS AND TRAINING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Applicable Certifications	# of Electrical Corporation Employees With Min Quals	# of Electrical Corporation Employees with Special Certifications	# of Contracted Employees With Min Quals	# of Contractor Employees With Applicable Certifications	Total # of Employees	Reference to Electrical Corporation Training/ Qualification Programs
Specialized Tree Equipment Operator	Shall be capable of operating two-handed equipment (chain saw, circular saw, and have the physical ability to endure extreme climate variances. Willing and able to obtain specialized training and certifications as required, such as tree species identification. Must be able to perform physical labor such as lifting a minimum of 50 lbs. to shoulder height or more.	N/A	0	0	145	N/A	145	N/A – Tree Work Training is not provided by PG&E.
(VMQC) Quality Management Auditor (PG&E Internal) *The title for contractors are in the process to change	Bachelor's degree in job-related discipline or equivalent experience. 3+ years of job-related experience. Valid CA Class C Driver's License or equivalent.	ISA Arborist. ISA Utility Specialist certification. ISA TRAQ. CPR/First Aid. OSHA 30.	60	50 = ISA Arborist; 24 = ISA Utility Specialist; 49 = ISA TRAQ; * Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	82	66 = ISA Arborist; 17 = ISA Utility Specialist; 60 = ISA TRAQ; * Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	142	Employees are profiled for training courses based on their roles.
(VMQC) Quality Management Auditor, Senior (PG&E Internal)	Bachelor's degree in job-related discipline or equivalent experience. 5+ years of job-related experience. ISA Arborist certification or ability to obtain it within 12 months. Valid CA Class C Driver's License or equivalent.	ISA Utility Specialist certification. ISA TRAQ. CPR/First Aid. OSHA 30.	26	22 = ISA Arborist; 10 = ISA Utility Specialist; 19 = ISA TRAQ; * Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	0	N/A	26	Employees are profiled for training courses based on their roles.
(VMQA) Program Manager (PG&E Internal) *The title for contractors are in the process to change	Bachelor's degree or equivalent experience. Job-related experience, 3 years minimum.	ISA Arborist. ISA Utility Specialist certification. ISA TRAQ.	8	8 = ISA Arborist; 6 = ISA Utility Specialist; 8 = ISA TRAQ; 4 = ASQ;* Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	0	N/A	8	Employees are profiled for training courses based on their roles.

TABLE 9-9:
VEGETATION MANAGEMENT QUALIFICATIONS AND TRAINING
(CONTINUED)

Worker Title	Minimum Qualifications for Target Role	Applicable Certifications	# of Electrical Corporation Employees With Min Quals	# of Electrical Corporation Employees with Special Certifications	# of Contracted Employees With Min Quals	# of Contractor Employees With Applicable Certifications	Total # of Employees	Reference to Electrical Corporation Training/ Qualification Programs
(VMQA) Program Manager, Senior (PG&E Internal)	Bachelor's degree in job-related discipline or equivalent experience. 5+ years of job-related experience. ISA Arborist certification or ability to obtain it within 12 months. Valid CA Class C Driver's License or equivalent.	ISA Utility Specialist certification. ASQ Certified Quality Auditor (CQA) certification. ISA TRAQ. CPR/First Aid.	2	2 = ISA Utility Specialist; 2 = ISA TRAQ;* Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	0	N/A	2	Employees are profiled for training courses based on their roles.
(VMQA) Compliance & Risk Consultant (PG&E Internal) *The title for contractors are in the process to change	Bachelor's degree in job-related discipline or equivalent experience. 3+ years of job-related experience. ISA Arborist certification or ability to obtain it within 12 months. Valid CA Class C Driver's License or equivalent.	ISA Utility Specialist certification. ASQ CQA certification. ISA TRAQ. CPR/First Aid.	3	2 = ISA Arborist; 2 = ISA TRAQ; * Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	4	4 = ISA Arborist; 1 = ISA Utility Specialist; 2 = ISA TRAQ; * Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	7	Employees are profiled for training courses based on their roles.
(VMQA) Compliance & Risk Consultant, Senior (PG&E Internal)	Bachelor's degree in job-related discipline or equivalent experience. 5+ years of job-related experience. ISA Arborist certification Valid CA Class C Driver's License or equivalent.	ISA Utility Specialist certification. ASQ CQA certification. ISA TRAQ. CPR/First Aid.	5	5 = ISA Utility Specialist; 3 = ISA TRAQ; * Note that due to the nature of the Credentials (Obtaining, expirations, renewals), the number is subject to changes.	0	N/A	5	Employees are profiled for training courses based on their roles.

Note: Please note employee and contractor employee totals, as well as certifications may fluctuate.
(a) Updated in accordance with Energy Safety's issuance of Revision Notice at 21.

9.13.1 Recruitment

In this section, the electrical corporation must describe how it recruits vegetation management and inspections personnel, including any relevant partnerships with colleges or universities.

PG&E leverages multiple channels to recruit qualified vegetation management and inspections personnel.

PG&E continues its partnership with educational institutions by providing funding and content maintenance support through cooperation with Upskill California and the California Community Colleges. The pre-inspector training curriculum was initially developed by Butte College and industry leaders. The curriculum is now being taught throughout California to introduce and recruit more people to the industry.

The colleges teaching the Pre-Inspector Training curriculum include:

- Butte College;
- College of the Sequoias;
- San Bernardino;
- Mendocino College;
- Mira Costa College;
- San Diego Community;
- Kern College;
- Shasta College;
- Folsom Lake College; and
- Santa Rosa Junior College.

9.13.2 Training and Retention

In this section, the electrical corporation must describe how it trains its vegetation management and inspection personnel, including any requirements for continued/refresher education and programs to improve worker qualifications.

PG&E's training program for its VMI and SVMI consists of formal courses (instructor-led and web-based) and on-the-job training. On-the-job training consists of onboarding sessions, in-field training, and periodic program and operations updates. Table PG&E-9-9 provides the current set of VMI web-based courses. VMIs and SVMIs also participate in refresher trainings.

TABLE PG&E-9-9:
PG&E VMI BASIC WEB-BASED COURSES

Course Number	Course Name	Description
VEGM0155WBT	Introduction To Vegetation Management	Safety Culture, Gov Regulations and Expectations.
VEGM0161WBT	Vegetation Management Patrol Safety	Procedure Access, Safety, How to prepare for the Work Day.
VEGM0165WBT	Overview Of PG&E Facilities	Introduction To Electrical Facilities
VEGM0170WBT	Evaluating Trees	Tree Growth, Tree Species Characteristics and Resources.
VEGM0175WBT	Identifying Tree Defects	Common Indicators of Tree Defects
VEGM0180WBT	VM Inspection Fundamentals	How To Inspect Vegetation Growing Near Facilities
VEGM0185WBT	Prescribing Tree Work	Priority Codes, Unified Work Codes, Proper Markings and Communication.
VEGM0190WBT	Abnormal Field Conditions	Abnormal Field Conditions: How To identify And Report Them
VEGM0195WBT	Major Woody Stems	How to Assess and Document Major Woody Stem
VEGM0198WBT	Positive Customer Relations	How To Demonstrate Positive Customer Relation Skills. Both on The Phone and in The Field.

Multiple programs are offered to improve work qualifications, which include:

- Updated training courses; and
- TRAQ-certification courses.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 10

SITUATIONAL AWARENESS AND FORECASTING

10. Situational Awareness and Forecasting

Each electrical corporation's Wildfire Mitigation Plan (WMP) must include plans for situational awareness.[170]

10.1 Targets

In this section, the electrical corporation must provide qualitative and quantitative targets for each year of this 3-year WMP cycle. The electrical corporation must provide at least one qualitative and quantitative target for the following initiatives:

- *Environmental Monitoring Systems (Section 10.2);*
- *Grid Monitoring Systems (Section 10.3);*
- *Ignition Detection Systems (Section 10.4);*
- *Weather Forecasting (Section 10.5); and*
- *Weather Station Maintenance and Calibration (Section 10.5.5).*

10.1.1 Qualitative Targets

The electrical corporation must provide qualitative targets for its 3-year plan for implementing and improving its situational awareness and forecasting,[171] *including the following:*

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable;*
- *A completion date for when the electrical corporation will achieve the target; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated.*

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[170] *Pub. Util. Code §§ 8386(c)(2)-(5).*

[171] *Annual information included in this section must align with the applicable data submission.*

10.1.2 Quantitative Targets

The electrical corporation must list all quantitative targets it will use to track progress on its situational awareness and forecasting in its 3-year plan, broken out by each year of the WMP cycle. Electrical corporations must show progress toward completing quantitative targets in subsequent reports, including data submissions and WMP Updates.[172] *For each target, the electrical corporation must provide the following:*

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s) used in past WMPs ("Previous Tracking ID"), if applicable;*
- *Projected targets and totals for each of the three years of the WMP cycle, e.g., [Year 1] end of year total, [Year 2] total, and [Year 3] total, 3-year total and the associated units for the targets; and*
- *The expected % risk reduction*[173] *for each of the three years of the WMP cycle.*

The electrical corporation's targets must provide enough detail to effectively inform efforts to improve the performance of the electrical corporation's situational awareness and forecasting initiatives.

Pacific Gas and Electric Company's (PG&E or the Company) Qualitative Targets (10.1.1) and Quantitative Targets (10.1.2) are summarized in Table 10-1 below.

- Reporting: PG&E will use the targets in Table 10-1 below for quarterly compliance reporting including the Quarterly Data Report (QDR), Quarterly Notification (QN), and the Annual Report on Compliance (ARC). We note that throughout this 2026-2028 WMP, we discuss current plans for wildfire-related activities beyond the targets in Table 10-1. The timing and scope of these additional activities may change. We will not be reporting on these activities in our QDR, QN, or ARC because they are not defined targets, but are described in our 2026-2028 WMP to provide a complete picture of our wildfire mitigation activities.
- External Factors: All targets throughout this WMP are subject to External Factors. External Factors in this context are reasonable circumstances that may impact execution against targets including, but not limited to, physical conditions, environmental delays, landowner or customer refusals or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, wildfires, exceptions or exemptions to regulatory/statutory requirements, and other safety considerations.

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172 *Annual information included in this section must align with the applicable data submission.*

173 *The expected % risk reduction is the expected percentage risk reduction per year, as described in Section 6.2.1.2.*

- Utility Initiative Tracking IDs (Tracking IDs): We are including Tracking IDs in each section that has associated targets. Table 10-1 includes the Tracking IDs we are implementing to tie the targets to the narratives in the WMP. The Tracking IDs will also be used for reporting in the QDR.

- % Risk Impact: The "% Risk Impact" is calculated based on the risk reduction of the mitigation initiative divided by total overall utility risk. The "% Risk Impact" provided is an estimate based on the best available workplans applied against the latest risk models as of the time of this filing. In many cases, the workplans contain units exceeding the target presented to ensure target completion is feasible. We anticipate that as mitigation work takes place and as risk models and workplans are updated, the estimated "% Risk Impact" projections could change. Additionally, because inspections do not reduce risk in isolation, for inspection and line sensor related targets we include an "eyes-on-risk" value to provide insights into the level of risk being assessed.

- High Fire Threat District (HFTD), High Fire Risk Area (HFRA), Buffer Zone Areas: Unless stated otherwise, all initiatives described in Table 10-1 either involve work or audits on units or equipment located in, traversing, or energizing HFTD, HFRA, or Buffer Zone areas.

TABLE 10-1:
SITUATIONAL AWARENESS TARGETS BY YEAR

Initiative	Quantitative or Qualitative Target	Activity (Tracking ID #)	Previous Tracking ID, if Applicable	Target Unit	2026 End-of-Year Total/ Completion Date	% Risk Reduction for 2026	2027 Total/ Status	% Risk Reduction for 2027[(a)]	2028 Total/ Status	% Risk Reduction for 2028[(a)]	3-Year Total	Section; Page Number
Situational Awareness and Forecasting	Quantitative	Line Sensor - Installations (SA-02)	SA-02	Sensor Locations	240	6.42% (Eyes on Risk)	240	6.42% (Eyes on Risk)	240	6.42% (Eyes on Risk)	720	10.3.1; p. 447
Situational Awareness and Forecasting	Qualitative	Evaluate camera AI system performance and new functionalities (SA-08)	SA-08	n/a	Completed; December 31, 2026	n/a	n/a	n/a	n/a	n/a	n/a	10.4.1; p. 455
Situational Awareness and Forecasting	Quantitative	Distribution Fault Anticipation (DFA) Installations (SA-10)	SA-10	Sensor Locations	15	9.92% (Eyes on Risk)	15	9.92% (Eyes on Risk)	15	9.92% (Eyes on Risk)	45	10.3.1; p. 447
Situational Awareness and Forecasting	Quantitative	Early Fault Detection (EFD) Installations (SA-11)	SA-11	Sensor Locations	180	2.52% (Eyes on Risk)	180	2.52% (Eyes on Risk)	180	2.52% (Eyes on Risk)	540	10.3.1; p. 447
Situational Awareness and Forecasting	Quantitative	Live Fuel Moisture Data Collection (SA)	n/a	Sample Locations	25	n/a	25	n/a	25	n/a	75	10.2.1; p. 437
Situational Awareness and Forecasting	Qualitative	Weather Station Network Evaluation (SA-13)	n/a	n/a	Completed; December 31, 2026	n/a	Completed; December 31, 2027	n/a	Completed; December 31, 2028	n/a	n/a	10.2.4; p. 446
Situational Awareness and Forecasting	Qualitative	SmartMeters next generation capability evaluation (SA-14)	n/a	n/a	Started; March 2026	n/a	In Progress; 2027	n/a	Completed; December 31, 2028	n/a	n/a	10.3.3; p. 452
Situational Awareness and Forecasting	Quantitative	Weekly uptime of Wildfire Cameras (SA-15)	n/a	Average weekly uptime percentage	90%	n/a	90%	n/a	90%	n/a	n/a	10.4.1; p. 455
Situational Awareness and Forecasting	Quantitative	Weather Model Verification Tool (SA-16)	n/a	Weather Model Verification Tool	1	n/a	n/a	n/a	n/a	n/a	1	10.5.3; p. 468
Situational Awareness and Forecasting	Qualitative	Weather Model Enhancements leveraging AI- ML (Machine Learning) (SA-17)	n/a	n/a	Started; March 2026	n/a	In Progress; 2027	n/a	Completed; December 31, 2028	n/a	n/a	10.5.3; p. 468
Situational Awareness and Forecasting	Quantitative	Weather Station Network Health (SA-18)	n/a	Percent of Weather Stations	95%	n/a	95%	n/a	95%	n/a	n/a	10.5.5; p. 469
Situational Awareness and Forecasting	Qualitative	Weather Station Network Optimization (SA-19)	n/a	n/a	Completed; December 31, 2026	n/a	Completed; December 31, 2027	n/a	Completed; December 31, 2028	n/a	n/a	10.5.5; p. 469

Note: Estimates for the 2027 and 2028 risk reduction are not available at the time of WMP submission. As such, 2026 risk reduction values will be used as a proxy.

10.2 Environmental Monitoring Systems

The electrical corporation must describe its systems and procedures for monitoring environmental conditions within its service territory. These observations should inform the electrical corporation's near-real-time risk assessment and weather forecast validation. The electrical corporation must document the following:

- *Existing systems, technologies, and procedures;*
- *How the need for additional systems is evaluated;*
- *Implementation schedule for any planned additional systems; and*
- *How the efficacy of systems for reducing risk are monitored.*

The electrical corporation must reference the Tracking ID where appropriate.

In the following sections, PG&E describes our environmental monitoring systems and technologies and the procedures we use to evaluate and reduce weather related risks within our service areas. We also outline our process for assessing new systems, expanding our existing systems, and evaluating the effectiveness of our environmental monitoring program.

10.2.1 Existing Systems, Technologies, and Procedures

Tracking ID: SA-12

The electrical corporation must report on the environmental monitoring systems and related technologies and procedures currently in use, highlighting any improvements made since the last WMP submission. The electrical corporation must discuss systems, technologies, and procedures related to the reporting of the following:

- *Current weather conditions:*
  - *Air temperature;*
  - *Relative humidity;*
  - *Wind velocity (speed and direction); and*
- *Fuel characteristics:*
  - *Seasonal trends in fuel moisture.*

Each system must be summarized in Table 10-2. The electrical corporation must provide the following additional information for each system in the accompanying narrative:

- *Generalized location of the system/locations measured by the system (e.g., HTFD, entire service territory);*
- *Integration with the broader electrical corporation's system;*
- *How measurements from the system are verified;*
- *Frequency of maintenance;*
- *For intermittent systems (e.g., aerial imagery, line patrols), what triggers collection. This should include flow charts and equations as appropriate; and*
- *For calculated quantities, how raw measurements are converted into calculated quantities. This should include flow charts and equations as appropriate.*

Table 10-2 below summarizes our environmental monitoring systems.

TABLE 10-2:
ENVIRONMENTAL MONITORING SYSTEMS

System	Measurement/ Observation	Frequency	Purpose and Integration
Weather stations	• Sustained wind speed • Wind gust speed • Air temperature • Relative humidity	The standard frequency is six observations per hour. However, up to 120 observations per hour can be enabled on most stations.	• Improving situational awareness • Assisting with Public Safety Power Shutoff (PSPS) event execution • Improving weather forecasts through data assimilation by the Meteorological Assimilation Data Ingest System (MADIS) • Validating the performance of the weather models
Fuel moisture sampling and modeling	The percentage of moisture in collected samples of specific plant species from 30 select HFTD locations across the service territory.	Once a month	• Validating the fuel moisture models • Improving situational awareness • Building robust historical fuel moisture datasets

Weather Stations

There is high wildfire risk across many remote areas within PG&E's service territory. California contains thousands of microclimates in which wind patterns differ based on location and topography (e.g., on a ridge, in a canyon, or on a valley floor). As weather events unfold, such as the Diablo and Santa Ana wind events, the complex dynamics of wind and terrain alignment, as well as boundary layer height, may result in downslope windstorms where wind speeds accelerate down mountain ranges and topographic features. Although there are hundreds of Remote Automatic Weather Station and National Weather Service (NWS) Weather Stations in remote areas of California, there are many locations where microscale effects can occur that could lead to devastating consequences. The PG&E weather station network provides additional coverage to verify weather conditions on the ground and build datasets to improve future models.

A primary benefit of weather station data is enhanced situational awareness into real-time weather-related risk. Our weather stations provide more spatial and temporal granularity into conditions than state and federal weather station networks. We use our weather stations to monitor temperatures, wind speeds, wind gusts, and RH, as they are crucial for decision making during PSPS events. Readings from stations are evaluated in real-time in the Emergency Operations Center (EOC) to inform PSPS decision-making and to validate safe conditions before the weather all clear is declared. These stations are also utilized to verify weather model forecast performance.

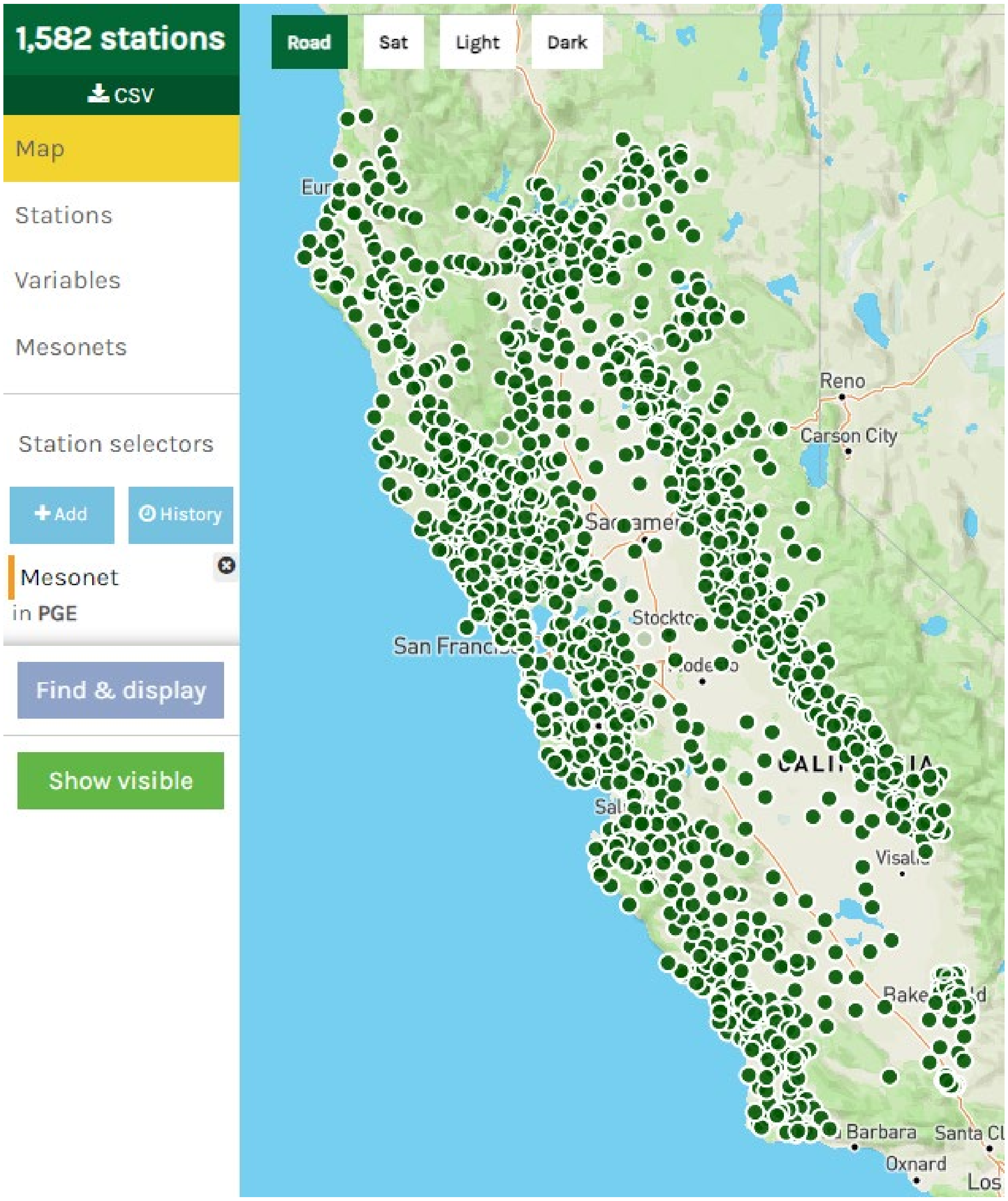
All weather station data is uploaded in real-time to the MADIS making it available to the meteorological community and the public. As a result, all our live and historical station data can be found on the NWS's Weather and Hazards Data Viewer: https://www.wrh.noaa.gov/map/?obs=true&wfo=sto.

Data from MADIS is also used by the National Center for Atmospheric Research (NCAR) to initialize Global Weather Models. These models are, in turn, used by PG&E to run our high-resolution weather models. Thus, increasing weather station coverage in California should lead to incremental improvements in NCAR's forecast ability.

Generalized Location of the System/Locations Measured by the System (e.g., HTFD, Entire Service Territory)

Our weather station coverage is primarily focused on the HFRA of our service territory. The station coverage as of January 13, 2025, is shown in Figure PG&E-10.2.1-1 below.

FIGURE PG&E-10.2.1-1:
PG&E'S WEATHER STATION COVERAGE AS OF JANUARY 13, 2025



Note: Source: [Metadata Explorer - Synoptic Data PBC]

Integration With the Broader Utility System

Weather station data are made publicly-available and are also available in our live Weather Map and the PSPS execution dashboard. These tools allow all PG&E users to visualize data from weather stations in relation to distribution and transmission lines. During PSPS events, weather station data is used to summarize the fire weather (wind, temp and humidity) in each area considered for PSPS.

Process to Verify Measurements From the System and Frequency of Maintenance

Each instrument is factory calibrated to ensure satisfactory data are collected once deployed. During installation, field technicians work with analysts from an external vendor to ensure proper data communications during the installation process. In the operational phase, the vendor performs automated checks on weather station data (e.g., range and reasonableness checks) and sends alerts on any stations that may need to be reviewed. In addition, operational meteorologists review data output through the course of business and flag suspect data. A ticket is created in internal systems and, if required, field crews are dispatched to verify and remedy issues. Ongoing calibrations and maintenance are performed on each station during each calendar year unless conditions prevent access to the location (e.g., customer refusal, impassable due to snow, safety).

Frequency of Maintenance

We strive to perform a site calibration including maintenance of each station at least once per calendar year. Site calibration is done by external and internal resources. This may not always be possible to achieve given the remoteness of many locations and the weather conditions in some areas (e.g., impassable due to snow).

For Intermittent Systems (e.g., Aerial Imagery, Line Patrols), the Processes Used to Trigger Collection

The weather stations regularly report data every 10 minutes via cellular or satellite communications. Meteorologists can enable more frequent data collection (every 30 seconds) from most weather stations if needed.

For Calculated Quantities, the Processes Used to Convert Raw Measurements to Calculated Quantities

The PG&E weather stations employ scientific-grade instruments to measure and report data. Specifically, they use the Campbell Scientific EE181 Temperature and Relative Humidity Probe and the Campbell Scientific 05103-l anemometer. Instrument specifications and measuring methodology can be found in instrument manuals found on Campbell Scientific's website: https://www.campbellsci.com.

For more information on PG&E's weather station maintenance and calibration, see PG&E's response to Areas for Continuous Improvement (ACI) PG&E-23-23 in Section B.5 of the 2025 WMP Update.

Fuel Characteristics: Seasonal Trends in Fuel Moisture

Measuring moisture content throughout the year in living and dead vegetation is a critical component of our environmental monitoring systems that help build our Fire Potential Index (FPI) Model, as well as the fire danger models used by state and federal fire agencies. To assess the FPI hour-by-hour and multiple days in advance, high resolution Dead Fuel Moisture (DFM) and Live Fuel Moisture (LFM) models are needed. The model outputs are used in the FPI, which informs PSPS decisions.

In addition to modeling LFM, we sample and observe LFM through our LFM Sampling Program. Each month, plant samples are collected and analyzed from at least 25 designated PG&E fuel sampling sites. See SA-12 in Table 10-1 in Section 10.1.2 for more information.

Generalized Location of the System/Locations Measured by the System (e.g., HTFD, Entire Service Territory)

Each LFM sampling location is in the HFRA. Collectively, these sites cover the entire PG&E service territory.

Integration With the Broader Utility System

Each month we compile an LFM report to aid our situational awareness. A sample from December 2024 is presented below (Figure PG&E-10.2.1-2). This report shows the latest LFM reading from each location and the general trend from the month prior. A timeseries plot is also generated to visualize the seasonal trends in chamise and manzanita vegetation to compare with the typical seasonal cycle.

FIGURE PG&E-10.2.1-2:
DECEMBER 2024 SAMPLE LFM REPORT

Chamise

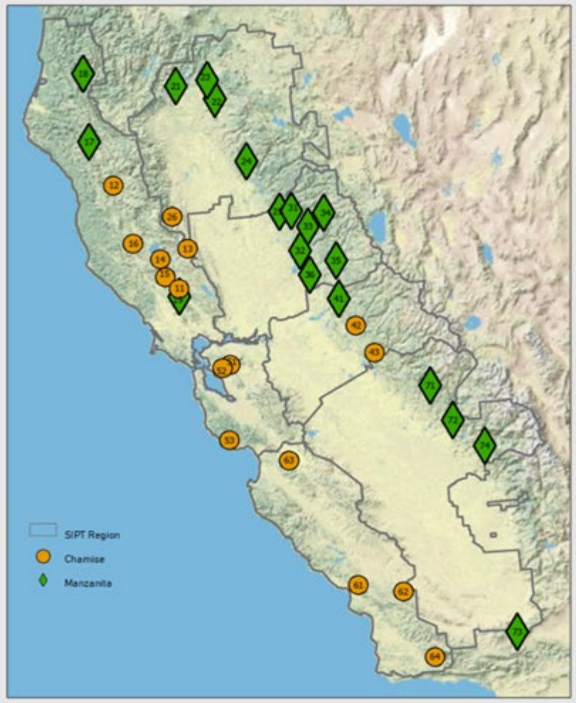
Site Number and Name	Elevation	Date	% Moisture	Trend ↗ ↘ →
North Coast				
#12 Poonkinney Ridge	2760'	12/19/2024	104	→
#13 Walker Ridge	2200'	12/19/2024	72	→
#14 Kelseyville	2400'	12/19/2024	70	↘
#15 Pine Flat	3200'	12/19/2024	72	→
#16 Lower Cow Mountain	1120'	12/4/2024	73	→
North Valley				
#26 Fouts Springs	1410'	12/8/2024	76	→
Central				
#42 Vallecito	2000'	12/3/2024	73	→
#43 Priest Grade	2500'	12/2/2024	67	→
Bay Area				
#51 Las Trampas	1300'	12/4/2024	68	→
#52 Oakland-Chabot	1090'	12/4/2024	66	→
#53 Bonny Doon	1600'	12/3/2024	56	→
South Coast				
#61 Templeton	1200'	12/18/2024	67	→
#62 Pozo	2100'	12/11/2024	66	→
#64 Happy Canyon	1270'	12/18/2024	71	→
		Chamise Average	71	→

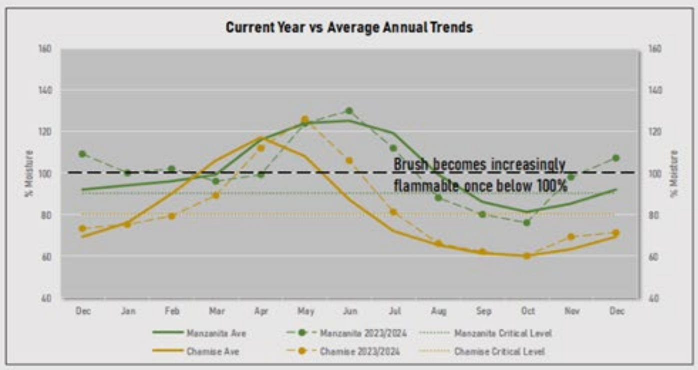
Manzanita

Site Number and Name	Elevation	Date	% Moisture	Trend ↗ ↘ →
North Coast				
#16 Lower Cow Mountain	1120'	12/4/2024	110	→
#17 Alderpoint	960'	12/19/2024	115	↗
North Valley				
#21 Shasta Dam	1430'	12/10/2024	100	→
#23 Oak Run	1930'	12/10/2024	104	→
#24 De Sabla	2640'	12/11/2024	112	→
#25 Oregon House	1850'	12/18/2024	106	→
Sierra				
#31 Sweetland	2000'	12/17/2024	129	↗
#33 Rollins Reservoir	2660'	12/2/2024	109	→
#34 Blue Canyon	5200'	12/2/2024	116	↗
#35 Pollock Pines	4300'	12/2/2024	104	↗
#36 Cameron Park	1450'	12/17/2024	98	↗
Central				
#41 Pine Acres	2700'	12/3/2024	86	↘
		Manzanita Average	107	↗

Total Samples Collected	83

PG&E Site Number and Plant Type



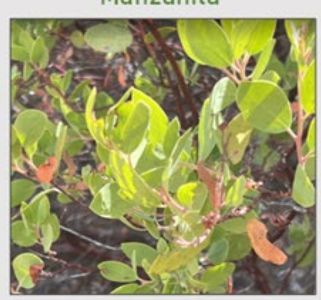


Chamise

Current and Average Monthly Values

	Chamise		Manzanita	
Month	2023/24	Ave	2023/24	Ave
Dec	73	69	109	92
Jan	75	76	100	94
Feb	79	90	102	96
Mar	89	106	96	99
Apr	112	117	99	116
May	126	108	124	124
Jun	106	87	130	125
Jul	81	72	112	119
Aug	66	65	88	99
Sep	62	61	80	86
Oct	60	60	76	81
Nov	69	61	98	86
Dec	71	69	107	92

Manzanita



Process to Verify Measurements From the System

Moisture content values are calculated by comparing the weight of the water in the sample to the weight of the oven-dried sample. These measurements are recorded and publicly archived in the National Fuel Moisture Database for the purposes of situational awareness across local, state and federal agencies and to bolster historical datasets. This process is relatively maintenance-free apart from basic lab equipment and field tools that are used to perform and process the sample.

Frequency of Maintenance

Sites are typically sampled once per month manually.

For Intermittent Systems (e.g., Aerial Imagery, Line Patrols), the Processes Used to Trigger Collection. This Should Include Flow Charts and Equations as Appropriate to Describe the Process

Sites are typically sampled once per month manually.

For Calculated Quantities, the Processes Used to Convert Raw Measurements to Calculated Quantities. This Should Include Flow Charts and Equations as Appropriate to Describe the Process

The formula for calculating percent of moisture content is:

$$\frac{(weight\ of\ water\ in\ sample)}{(dry\ weight\ of\ sample)}\ (100) = \text{percent of moisture content.}$$

10.2.2 Evaluation and Selection of New Systems

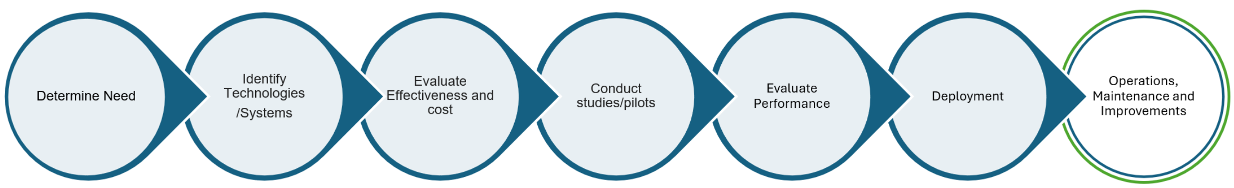
The electrical corporation must describe how it evaluates the need for additional environmental monitoring systems. This description must include:

- *How the electrical corporation evaluates the impact of new systems on reducing risk (e.g., expected quantitative improvement in weather forecasting); and*
- *How the electrical corporation evaluates the efficacy of new technologies.*

These descriptions must include flow charts as appropriate.

We interpret this section as referring to additional systems or networks as opposed to adding incremental sensors to existing systems (e.g., a new weather station). Below is a high-level flow chart illustrating the general evaluation process.

FIGURE PG&E-10.2.2-1:
HIGH LEVEL GENERAL EVALUATION PROCESS FLOWCHART



For example, after we determine a need for an additional environmental monitoring system we work with internal experts, as well as external experts such as the San Jose State Fire Weather Research Laboratory and Wildfire Interdisciplinary Research Center. One example project is focused on evaluation of new sensor technologies to measure soil moisture and DFM. Results from these studies are not yet available. However, we will continue to utilize a variety of environmental monitoring systems including weather stations, cameras, and satellite data as described elsewhere in the WMP.

10.2.3 Planned Improvements

The electrical corporation must describe its planned improvements for its environmental monitoring systems.[174] *This must include any plans for the following:*

- *Expansion of existing systems; and*
- *Establishment of new systems.*

We are not currently planning implementation of new environmental monitoring systems or new networks.

10.2.4 Evaluating Activities

Tracking ID: SA-12; SA-13

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its environmental monitoring activity (program).

The meteorology team has analysts assigned to the weather station and fuel/soil moisture monitoring programs who evaluate the performance of each program. Evaluation activities are associated with and discussed in SA-12 and SA-13 in Table 10-1 in Section 10.1.2 for more information. For example, the lead weather station analyst, who is responsible for selecting locations for potential weather station installations, annually reviews the network performance and station coverage to inform the strategy for installations and optimizations each calendar year.

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[174] *Annual information included in this section must align with the applicable data submission.*

10.3 Grid Monitoring Systems

The electrical corporation must describe its systems and procedures used to monitor the operational conditions of its equipment.[175] *These observations should inform the electrical corporation's near-real-time risk assessment. The electrical corporation must document:*

- *Existing systems, technologies, and procedures;*
- *Procedure used to evaluate the need for additional systems;*
- *Implementation schedule for any planned additional systems; and*
- *How the efficacy of systems for reducing risk are monitored.*

The electrical corporation must reference the Tracking ID where appropriate.

Tracking ID: SA-02; SA-10; SA-11

Below we describe how our grid monitoring systems, technologies, and associated procedures help us evaluate and monitor grid equipment within our service areas. Existing systems include Line Sensors, DFA technology, EFD technologies, and Reclosers. We also outline our evaluation process for potential new systems, expansion of our existing systems, and how we evaluate the efficacy of our grid monitoring program.

10.3.1 Existing Systems, Technologies, and Procedures

Tracking ID: SA-02; SA-10; SA-11

The electrical corporation must report on the grid system monitoring systems and related technologies and procedures currently in use, highlighting any improvements made since the last WMP submission. At a minimum, the electrical corporation must discuss systems, technologies, and procedures related to the detection of:

- *Faults (e.g., fault anticipators, rapid earth fault current limiters, etc.);*
- *Failures; and*
- *Recloser operations.*

Each system must be summarized in Table 10-3 below. The electrical corporation must provide the following information for each system in the accompanying narrative:

- *Location of the system/locations measured by the system;*

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[175] *Pub. Util. Code §§ 8386(c)(3), (6), (22).*

- *Integration with the broader electrical corporation's system;*
- *How measurements from the system are verified; and*
- *For intermittent systems (e.g., aerial imagery, line patrols), description of what triggers collection. This must include flow charts and equations where appropriate.*

For calculated quantities, how raw measurements are converted to calculated quantities. This must include flow charts and equations where appropriate.

Table 10-3 below summarizes our grid operation monitoring systems.

TABLE-10-3:
GRID OPERATION MONITORING SYSTEMS

System	Measurement/ Observation	Frequency	Purpose and Integration
Line sensors	Current/fault current	15 minutes/triggered by fault magnitude threshold.	The detection and assistance in locating faults. In process of being integrated into analytics platform.
DFA	Current/voltage power flow anomalies	256 samples per cycle continuous. Event capture triggered by condition-based thresholds.	The detection and assistance in locating faults, abnormal power flow events, categorization of events. In process of being integrated into analytics platform.
EFD	Using sensors that monitor the Radio Frequency (RF) spectrum, the system detects the generation of Partial Discharge (PD) which is an indicator of equipment electrical degradation or arcing. Using measured accumulation of PD, the system can identify the location of these issues.	1:25 duty cycle (Gen 3), continuous (Gen 4). Events matched based on timing and location on monitored circuit segments.	To detect failing equipment early and to detect vegetation encroachment. Plan to integrate into analytics platform.
Reclosers	Current/voltage/ power/fault data	Continuously	This data is used to provide real-time fault information as well as to assist in diagnosing system problems during and after events occur.

Fault Detection

Location of the System/Locations Measured by the System

PG&E has 1295 Line Sensor locations on 297 circuits and one DFA sensor each on 96 circuits as of end-of-year 2024. PG&E plans to install Line Sensors on 240 additional locations each year and 15 DFA locations each year between 2026 and 2028. These sensors will be predominantly located in Tier 2 and Tier 3 HFTD.

How Measurements From the System Are Verified

Line Sensor measurements are verified by monitoring acceptable current to fault conditions.

DFA measurements are verified by monitoring acceptable current and voltage power flow anomalies.

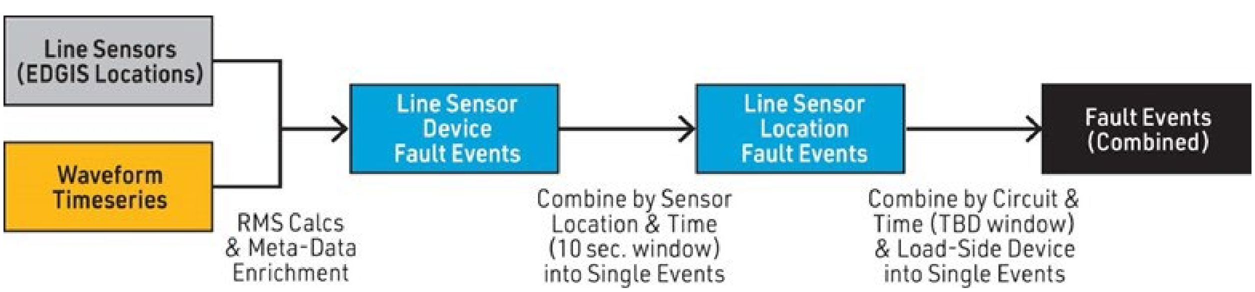
For Intermittent Systems (e.g., Aerial Imagery, Line Patrols), What Triggers Collection

These systems are continuous monitoring systems.

For Calculated Quantities, How Raw Measurements Are Converted to Calculated Quantities

Line Sensors and DFA detect abnormal current or events. The data from these systems have been integrated into Foundry so that the data can be analyzed and approximate area of possible fault or disturbance calculated based on the circuit model impedance from the CYME power flow tool. Also, by taking advantage of repeated events where the cause is "unknown," the tool can use the accumulated data to better determine anomaly locations. Figure PG&E-10.3.1-1 below illustrates a fault events workflow. Processes and procedures have been developed to track field investigations and resulting risk mitigation activities that are initiated based on line sensor/DFA-triggered alarms.

FIGURE PG&E-10.3.1-1:
ILLUSTRATIVE FAULT EVENTS WORKFLOW



Failure Detection

Location of the System/Locations Measured by the System

As of December 31, 2024, PG&E has deployed EFD sensors at 203 locations on eight circuits. Processes and procedures have been developed to track field investigations and resulting risk mitigation activities that are initiated based on EFD alerts.

Integration With the PG&E System

EFDs provide early detection of failing equipment and have the potential to detect vegetation encroachment. PG&E has plans to integrate EFD data into the Foundry analytics platform.

How Measurements From the System Are Verified

EFD measurements are verified by monitoring the RF spectrum of the system for generated PD indications, which are an indicator of equipment electrical degradation or arcing. Using measured accumulation of PD, the system can identify these issues are occurring.

For Intermittent Systems (e.g., Aerial Imagery, Line Patrols), What Triggers Collection

Using 1:25 duty cycle (Gen 3) or continuous (Gen 4) for collection, EFD events are matched based on timing and location on monitored circuit segments.

For calculated Quantities, How Raw Measurements Are Converted to Calculated Quantities

The response to this prompt in the Faults section above applies to Failures as well.

Recloser Operations

Location of the System/Locations Measured by the System

Reclosers are placed throughout our grid network, along utility lines.

Integration With the PG&E system

Recloser data is used to provide real-time fault information and assist in diagnosing system problems during and after events. Recloser operations can be detected with Supervisory Control and Data Acquisition (SCADA)-enabled LRs, Line Sensors, and DFA, along with SmartMeter devices using outage alarms. SCADA LRs and SmartMeter outage alarms are currently used to capture LR operation.

How Measurements From the System Are Verified

Reclosers measurements are verified by assessing changes from normal current, voltage, power, and fault data.

For Intermittent Systems (e.g., Aerial Imagery, Line Patrols), What Triggers Collection

Reclosers data is collected continuously.

For Calculated Quantities, How Raw Measurements Are Converted to Calculated Quantities

The response to this prompt in the Fault Detection section above applies to reclosers as well.

10.3.2 Evaluation and Selection of New Systems

The electrical corporation must describe how it evaluates the need for additional grid operation monitoring systems. This description must include:

- *How the electrical corporation evaluates the impact of new systems on reducing risk (e.g., expected reduction in ignitions from failures, expected reduction in failures); and*
- *How the electrical corporation evaluates the efficacy of new technologies.*

These descriptions must include flow charts where appropriate.

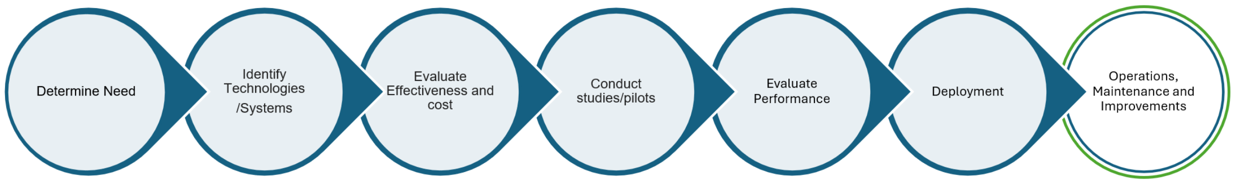
PG&E evaluates new grid operation monitoring systems that have the potential to address gaps in capability or performance of existing systems in reducing wildfire risk. PG&E evaluates the impact of new systems on reducing risk by using risk models and calculating, for example, expected reduction in ignitions from failures or expected reduction in failures. We also evaluate new technologies using quantitative performance and risk reduction metrics. Evaluation criteria also include compatibility of new technologies with our existing systems and work methods.

The process for evaluating the efficacy of new technologies and selecting additional grid operation monitoring systems is as follows and is summarized in the flow chart below:

1) Determine the need for additional monitoring systems to provide risk reduction;
2) Identify candidate technologies that could meet that need;
3) Evaluate how effective and efficient are each of the options;
4) Conduct pilots of selected technologies;
5) Evaluate the performance of different technologies against quantitative performance metrics; and
6) Plan deployment for selected monitoring technologies.
7) Operations, maintenance and incremental improvements

See the flowchart in Figure PG&E-10.3.2-1 below.

FIGURE PG&E-10.3.2-1:
EVALUATION OF NEW TECHNOLOGIES EFFICACY FLOWCHART



10.3.3 Planned Improvements

Tracking ID: SA-02; SA-10; SA-11; SA-14

The electrical corporation must describe its planned improvements in its grid operation monitoring systems. This must include any plans for the following:

- *Expansion of existing systems; and*
- *Establishment of new systems.*

Expansion of Existing Systems:

PG&E plans to expand the footprint of Line Sensors (SA-02), Distribution Fault Anticipation Sensors (SA-10) and Early Fault Detection Sensors (SA-11) during the 2026-2028 period. Please see Table 10-1 for details.

Establishment of New Systems:

PG&E plans to evaluate next generation SmartMeter technology's capabilities for wildfire risk reduction and develop a path to production if technology is found to be viable (SA-14). Next generation SmartMeter platforms combine edge computing, real-time analytics, and machine learning enabling distributed intelligence-based applications to make scalable grid-edge decisions that can identify anomaly signatures consistent with potential ignitions along the shared secondary network.

10.3.4 Evaluating Activities

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its grid operation monitoring activity (program).

We continually evaluate the efficacy of our grid operation monitoring systems through several built-in verification methods. Sensor installation completions are tracked in the Enterprise Workflow management system (SAP). Sensor alerts and corresponding field investigation findings are tracked in our analytics platform (Foundry).

We track sensor installations using SAP, our work management system. SAP installation job packages, which include field work checklists and verification of successful communication of sensors with their respective head-end systems, are checked to confirm proper installation and commissioning. Installation documentation and sensor communication reports are audited by our Compliance and Operational Assurance (COA) Team.

PG&E's Asset Health and Performance Center reviews alerts from deployed sensors. If desktop analysis indicates the need for further review, a field investigation is requested. Any field findings and resulting remediations are tracked on the analytics platform Foundry enabling us to assess effectiveness of sensor technologies in reducing wildfire risk.

10.4 Ignition Detection Systems

The electrical corporation must describe its systems, technologies, and procedures used to detect ignitions within its service territory and gauge ignition size and growth rates.[176]

The electrical corporation must document the following:

- *Existing ignition detection sensors and systems;*
- *Evaluation and selection of new ignition detection systems;*
- *Planned integration of new ignition detection technologies;*
- *Identify venues for routine sharing of the following:*
  - *Evaluation of strengths and limitations of new technology;*
  - *Case studies/lessons learned regarding new ignition detection systems and new ignition detection technologies;*

Lessons learned; and

- *Monitoring of initiative improvements.*

The electrical corporation must reference the Tracking ID where appropriate.

In this section, we describe our ignition detection systems, technologies, and procedures used to detect and evaluate ignition size and growth rates within our service areas. Existing systems include our Fire Detection and Alerting System (FDAS), and AI-enabled Wildfire Cameras. We also outline our process for assessing new systems, expanding existing systems, and evaluating the efficacy of our ignition detection program.

10.4.1 Existing Ignition Detection Sensors and Systems

Tracking ID: SA-08; SA-15

The electrical corporation must report on the sensors and systems, technologies, and procedures for ignition detection that are currently in use, highlighting any improvements made since the last WMP submission. At a minimum, the electrical corporation must document the deployment of each of the following:

- *Early fire detection including, for example:*
  - *Satellite infrared imagery;*

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[176] *Pub. Util. Code § 8386(c)(3).*

- *High-definition video;*
- *Infrared cameras; and*

- *Fire growth potential software.*

The electrical corporation must summarize each system in Table 10-4 below. It must provide the following additional information for each system in an accompanying narrative:

- *General location of detection sensors (e.g., HFTD or entire service territory);*
- *Resiliency of sensor communication pathways;*
- *Integration of sensor data into machine learning or AI software;*
- *Role of sensor data in risk response;*
- *False positives filtering;*
- *Time between detection and confirmation; and*
- *Security measures for network-based sensors.*

Table 10-4 below summarizes our Fire Detection Systems currently deployed.

TABLE 10-4:
FIRE DETECTION SYSTEMS CURRENTLY DEPLOYED

Detection System	Capabilities	Companion Technologies	Contribution to Fire Detection and Confirmation
PG&E FDAS	Satellite detection and alerts from six satellites. Update cadence is every five minutes.	None	Provides valuable information to the utility and the public regarding the presence of new fires and the spread of existing fires in a timely fashion.
Wildfire Cameras w/AI detections	Over 600 cameras sponsored covering over 90 percent of the HFTD Tier 2 and 3 areas.	None	Video cameras allow fast and accurate detection or confirmation of wildfires, which can help operators assess the scope of resource response needed. Cameras have been equipped with AI smoke detection.

Early Fire Detection

Satellite Infrared Imagery, Wildfire Cameras With AI capabilities

General Location of Detection Sensors

Early fire detection systems, including satellite infrared imaging, high-definition video, and land based infrared cameras are located throughout the entire PG&E service territory including the HFTD areas. For our FDAS, PG&E uses data from six satellites.

Resiliency of Sensor Communication Pathways

Cameras: Currently there are no redundancies on communication pathways, which are typically dependent on wireless providers. Sensor assets—including their communication pathways—are owned by the service provider (e.g., University of California, San Diego, or Alert California) and maintained by the providers through either direct service or via contracted Wireless Internet Service Providers (who also install the cameras). PG&E accesses these sensors as part of a sponsor agreement with the agencies that own them.

Satellites: The satellites are operated by National Oceanic and Atmospheric Administration (NOAA). The Space Science and Engineering Center (SSEC) processes the data and provides it to PG&E. The SSEC has a dedicated production and backup server for redundancy. The satellites are also independent and the FDAS system can operate with one or all satellites functioning.

Integration of Sensor Data into Machine Learning or AI Software

Given the large number of cameras and areas to monitor, we worked with multiple vendors to discuss how we can use AI to help detect new fires and enhance situational awareness. The cameras are now equipped with AI technology where smoke can be detected using AI algorithms.

Role of Sensor Data in Risk Response

Cameras: PG&E has sponsored over 600 wildfire cameras on the Alert California network since 2019. Camera detections also provide valuable information about the presence of new fires and the spread of existing fires. These cameras are being used by first responders including CAL FIRE.

Satellites: Satellite fire detection provides valuable information quickly about the presence of new fires and the spread of existing fires. This information is used to ensure the safety of utility workers in the area, to help identify assets at risk, and provides situational awareness as to the burn intensity and rate of spread.

False Positives Filtering

For wildfire cameras, AI software is used to analyze and learn image elements (e.g., smoke location and color, direction of smoke column, etc.) that may indicate the presence of fire in an area.

For satellite fire detections, we work with the SSEC and use NOAA sources to consolidate detections. Algorithms they develop process the data to assign confidence intervals to each detection and flag potential false positives.

Time Between Detection and Confirmation

For cameras, AI fire detections provide valuable information to PG&E and first responder agencies regarding the presence of new fires. When AI detects new fires, notifications to the utility and first responders can occur more quickly than relying solely on other means of detection. Based on the AI system, updates occur every ten seconds. See SA-08 and SA-15 in Table 10-1 in Section 10.1.2 for more information regarding the Weekly uptime of Wildfire Cameras and AI system performance evaluation.

It takes about 10 minutes to process the satellite data so that it is available in FDAS.

Security Measures for Network-Based Sensors

The cameras use an encrypted, secure connection that ensures image integrity from the originating camera view to the remote viewer.

The FDAS system does not use network-based sensors.

10.4.2 Evaluation and Selection of New Detection Systems

The electrical corporation must describe how it evaluates the need for additional ignition detection technologies. This description must include:

- *How the electrical corporation evaluates the impact on new detection technologies on reducing and improving detection and response times;*
- *How the electrical corporation evaluates the efficacy of new technologies; and*
- *The electrical corporation's budgeting process for new detection system purchases.*

We are always looking for new and updated technologies that may help improve our work through our relationships with partner agencies, industry technology incubation consortia, emerging technology discovery services, vendors, and through our Functional Area (FA) Research and Development teams. We conduct a rigorous and detailed vetting process to evaluate new technologies and determine if they may be useful in our detection system environment.

Our impact, efficacy, and budgeting evaluation of emerging technologies generally follows the process below:

1) Identifying new technologies or systems;

2) Conducting a Subject Matter Expert (SME) and business review for reasonableness and feasibility;

3) Evaluating alignment to program goals and objectives;

4) Benchmarking, if applicable;

5) Determining a source of funding and cost review;

6) Performing a pilot study, if needed, to evaluate effectiveness at achieving program goals and objectives and testing assumptions;

7) Implementing and deploying the technological system; and

8) Conducting a SME operational review of benefits.

10.4.3 Planned Integration of New Ignition Detection Technologies

The electrical corporation <u>must provide</u> an implementation schedule for new ignition detection and alarm system technologies. This <u>must include</u> any plans for the following:

- *Integration of new systems into existing physical infrastructure;*
- *Integration of new systems into existing data analysis; and*
- *Increases in budgets and staffing to support new systems.*

There are no planned integrations of new ignition detection technologies.

10.4.4 Evaluating Activities

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its fire detection systems.

Our Hazard Awareness and Warning Center team partners with internal SMEs to conduct ongoing evaluations of the efficacy of our fire detection systems. These teams use wildfire data, lessons learned from fire events and collaborate with external agencies.

10.5 Weather Forecasting

The electrical corporation must describe its systems and procedures used to forecast weather within its service territory.[177] *These forecasts must inform the electrical corporation's near-real-time-risk assessment and PSPS decision-making processes. The electrical corporation must document the following:*

- *Its existing modeling approach;*
- *The known limitations of its existing approach;*
- *Implementation schedule for any planned changes to the system; and*
- *How the efficacy of systems for reducing risk are monitored.*

The electrical corporation must reference the Tracking ID where appropriate.

High-impact weather events test the reliability and durability of power utilities and can be challenging to forecast and manage operationally. Examples of high-impact weather events include high winds from winter storms or offshore and dry wind events, which can topple powerlines; hot and dry conditions, which can result in wildfires, especially when driven by high winds; and heat waves, which can result in high electric loads, leading to equipment stress and possible rotating power outages. In this section we describe the operational forecast system deployed.

Our modeling framework, accuracy testing and methodology is discussed at length in a peer-reviewed and open-access article in *Atmosphere.*[178]

10.5.1 Existing Modeling Approach

At a minimum, the electrical corporation must discuss the following components of weather forecasting:

- *Data assimilation from environmental monitoring systems within the electrical corporation service territory;*
- *Ensemble forecasting with control forecast and perturbations;*
- *Model inputs, including, for example:*
  - *Land cover/land use type;*

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[177] *Pub. Util. Code § 8386(c)(3).*

[178] Carpenter et al., *Improving a WRF-Based High-Impact Weather Forecast System for a Northern California Power Utility*, Atmosphere (Oct. 19, 2024), available at: https://doi.org/10.3390/atmos15101244.

- *Local topography;*

- *Model outputs, including, for example:*
  - *Air temperature;*
  - *Barometric pressure;*
  - *Relative humidity;*
  - *Wind velocity (speed and direction);*
  - *Solar radiation;*
  - *Rainfall duration and amount;*
- *Separate modules (e.g., local weather analysis and local vegetation analysis);*
- *SME assessment of forecasts;*
- *Spatial granularity of forecasts, including:*
  - *Horizontal resolution;*
  - *Vertical resolution; and*
- *Time horizon of the weather forecast throughout the service territory.*

The electrical corporation must highlight improvements made to the electrical corporation's weather forecasting since the last WMP submission.

The electrical corporation must also provide documentation of its modeling approach pertaining to its weather forecasting system in accordance with the requirements in Appendix B.

Model Overview

PG&E builds, operates, and maintains core models and datasets used to train machine learning models and forecast PSPS events. This section provides details on these foundational datasets and models.

PG&E partners with two external experts and employs internal weather modeling experts to deploy and maintain PG&E's high-resolution weather models. In 2014 PG&E partnered with Weather Decision Technology—since acquired by DTN, a weather forecasting company formerly known as Telvent DTN, Data Transmission Network and Dataline—to deploy the first Version of PG&E's Operational Mesoscale Modeling System (POMMS), which is based on the Weather Research and Forecast (WRF) Model. A second external expert has also been engaged since 2014, Atmospheric Data Solutions (ADS), which was recently acquired by Technosylva. ADS-Technosylva has extensive knowledge of California fire weather and numerical weather prediction using

WRF and they work extensively with Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and other utilities, as well as firefighting agencies across the world.

WRF is a mesoscale numerical weather prediction system designed for both atmospheric research and operational forecasting applications. It features two dynamical cores, a data assimilation system, and a software architecture supporting parallel computation and system extensibility. WRF is currently being used operationally at National Centers for Environmental Prediction (NCEP) and other national meteorological centers and in real-time forecasting configurations at laboratories, universities, utilities and hundreds of companies.

PG&E first deployed the high resolution in-house mesoscale forecast model, POMMS, in November of 2014, and PG&E continues to improve and build upon the model framework to generate short to medium-term weather, outage, and fire potential forecasts across PG&E's service territory. We are currently on Version 4.0 of the core model; Table PG&E-10.5-1 below shows the model evolution:

TABLE PG&E-10.5-1
PG&E OPERATIONAL MESOSCALE MODELING SYSTEM DEVELOPMENT

POMMS Version	Year Implemented	WRF Version	Key Features
1	2014	3.5.1	Single 3 kilometer (km) grid using boundary conditions from a 12 km WRF run.
2	2018	4.0.2	Nested 3 km grid, Mellor-Yamada-Nakanishi-Niino (MYNN) surface layer scheme, Rapid Update Cycle (RUC) land surface model, 30-year reanalysis.
3	2020	4.1.2	Nested 2 km grid, Noah-MP land surface model, stochastically perturbed ensemble, 30-year reanalysis. See text and Table 2 for details.
4	2024	4.5.2	Nested 2 km grid, irrigation triggered by crop-growing season, Global Ensemble Forecasting System (GEFS)-based ensemble, 30-year reanalysis.

POMMS is a high-resolution weather forecasting model that generates important fire weather parameters including wind speed, temperature, Relative Humidity (RH), and precipitation. Outputs from POMMS are used as inputs to the Nelson DFM model, and LFM models developed by Technosylva to derive key fire danger indicators such as 1 hr., 10 hr., 100 hr., 1,000 hr. DFM, and LFM for multiple plant species.

30+ year climatologies of the same outputs have been produced and maintained since 2019 and provide the same horizontal and temporal resolution as well as model physics to the operational forecast model. These climatologies are utilized with fire occurrence datasets and outage datasets to build machine learning FPI and outage-ignition models that are utilized for PSPS.

The current POMMS model configuration deployed is WRF model Version 4.5.2, which provides data at 2x2 km spatial and hourly temporal resolution. A nested grid configuration of 18-, 6-, 2-, and 0.67-km (on demand) grids horizontal grids are utilized. Adaptive time stepping is used for computational efficiency and the model was configured to run in the Amazon Web Services (AWS) cloud across different AWS regions for redundancy. The POMMS forecasts include two deterministic forecasts, as well as a 9-member ensemble dynamically selected from the Global Forecast System (GFS) ensemble suite. One deterministic model is initialized using ¼° output from the NCEP – GFS model data, as well as 1/12° Sea Surface Temperature analyses. The GFS, often referred to as the American Model, is operated and maintained by NOAA's National Center for Environmental Prediction and is the United States' flagship global model. The second deterministic model is initialized with the European Center for Medium Range Weather Forecast (ECMWF) global model.

Data Assimilation From Environmental Monitoring Systems Within the Electrical Corporation Service Territory

Data assimilation from monitoring systems is discussed in the weather station section above. Observations are assimilated on the outermost grid and 3DVAR data assimilation is applied on the outer grid too using conventional surface and upper-air observations, as well as aircraft data, from the MADIS. The forecasts are also initialized using 1/4 GFS forecast data and 1/12°Sea Surface Temperature analyses.

Ensemble Forecasting With Control Forecast and Perturbations

Two control or deterministic models are initialized using the GFS and ECMWF deterministic outputs. An ensemble of nine members is also generated using an intelligent sub-selection of the NOAA GEFS saving considerable computing and financial resources. The GEFS is a stochastically perturbed 30-member ensemble based on the GFS. The ensemble members utilize the GFS analysis perturbed by a 6 h Ensemble Kalman Filter forecast ensemble. Model uncertainty is introduced using the Stochastically Perturbed Physics Tendencies and Stochastic Kinetic Energy Backscatter schemes. The computational cost would be prohibitive if we were to initialize a high-resolution WRF forecast corresponding to each GEFS member individually. We therefore tested a novel forecast strategy using nine representative GEFS members that are dynamically selected to maintain the large-scale flow diversity of the entire GEFS ensemble. The intended outcome is a WRF ensemble that is more accurate than a single WRF forecast at a higher resolution, yet also that provides meaningful information about forecast uncertainty at a drastically reduced cost. This selection strategy involves analyzing the GEFS forecast 500 Hectopascals geopotential height field (Z500) for each GEFS members. Selecting GEFS members to downscale consists of two steps intended to sample the mean and diversity of the ensemble. The first step involves a Self-Organizing Map (SOM), which is an artificial neural network (AI) used as a clustering method to group together events with similar structure. The SOM analysis is used to classify the GEFS ensemble into five nodes. Overall, we selected the nine GEFS members that captured both the mean and outlier behavior of the large-scale flow in the full ensemble and use these distinct members from the 00Z and 12Z GEFS packages to downscale. Thus, each forecast update utilized different ensemble members as determined by this methodology.

Model Outputs Including, for Example:

- Air temperature;
- Barometric pressure;
- Relative humidity;
- Wind velocity (speed and direction);
- Solar radiation; and
- Rainfall duration and amount.

We output and save 15 weather variables at the surface shown in Table PG&E-10.5.1-1 below. More variables are calculated but output is reduced to save storage size and costs (as discussed in the next section).

TABLE PG&E-10.5.1-1:
WEATHER VARIABLES

Variable	Description
Q2	Water vapor mixing ratio
T2	Temperature at 2 m
PSFC	Surface pressure
U10	10 m u wind component
V10	10 m v wind component
TSLB	Soil temperature
SMOIS	Soil moisture
ACSNOM	Accumulated melted snow
SNOWH	Physical snow depth
SWDOWN	Shortwave incoming radiation
ZNT	Time-varying roughness length
UST	Friction velocity
PREC_ACC_C	Accumulated Cumulus precipitation
PREC_ACC_NC	Accumulated Grid scale (non-convective) precipitation
SNOW_ACC_NC	Accumulated snow water equivalent

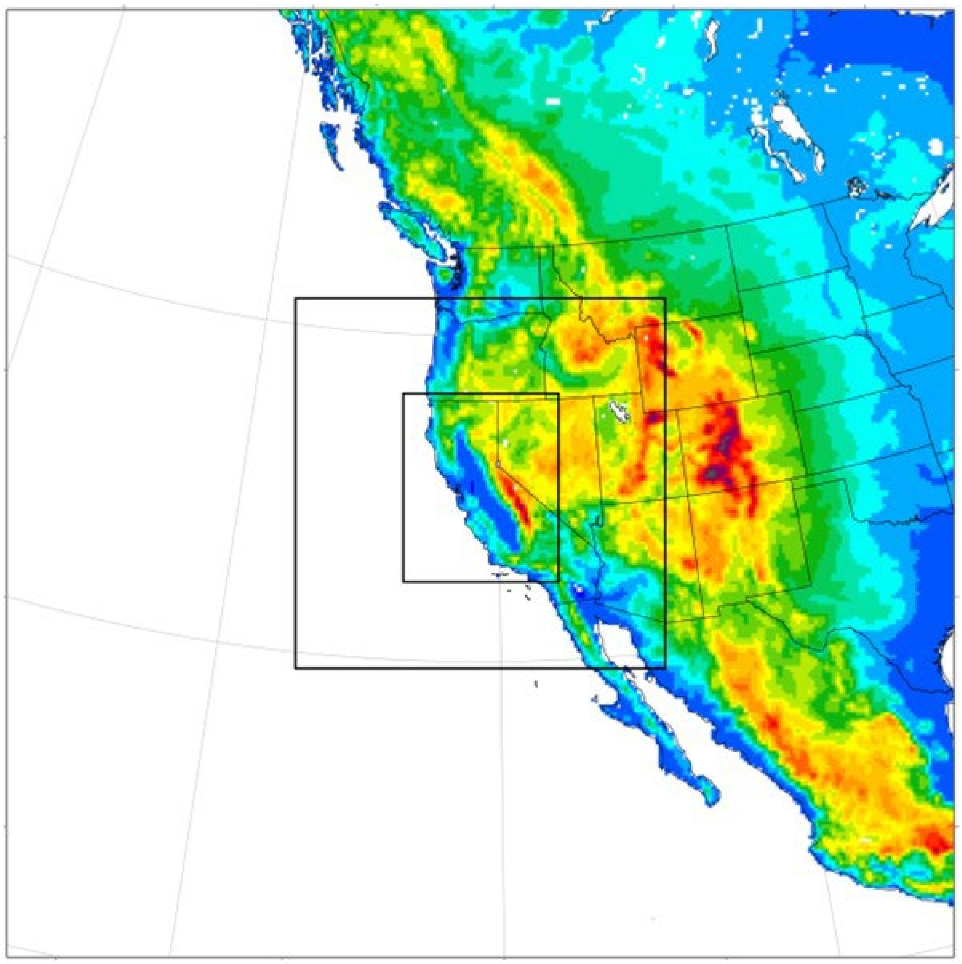
Separate Modules (e.g., Local Weather Analysis and Local Vegetation Analysis)

- SME Assessment of Forecasts: Operational meteorologists use our high-resolution weather model daily to forecast temperatures, storm impact, and PSPS events. Data outputs are typically reviewed multiple times per day by multiple SMEs. In addition, we have meteorologists and numerical weather prediction experts on staff that review model inputs and outputs through the normal course of business. Outputs are also compared to externally generated forecasts from other agencies like the NWS.

- <u>Spatial Granularity of Forecasts</u>: The base horizontal resolution is 2x2 km (2 km) for the control and ensemble forecasts. On demand forecasts during high-risk periods can be manually scheduled by SMEs and provide data every 0.67 x 0.67 km. The intelligent GEFS ensemble methodology and on-demand sub-kilometer options provide considerable cost savings. In our experiments, computing cost to forecast on a base 1 km grid was found to be 6.2 times greater than using a 2 km grid for a single model run.

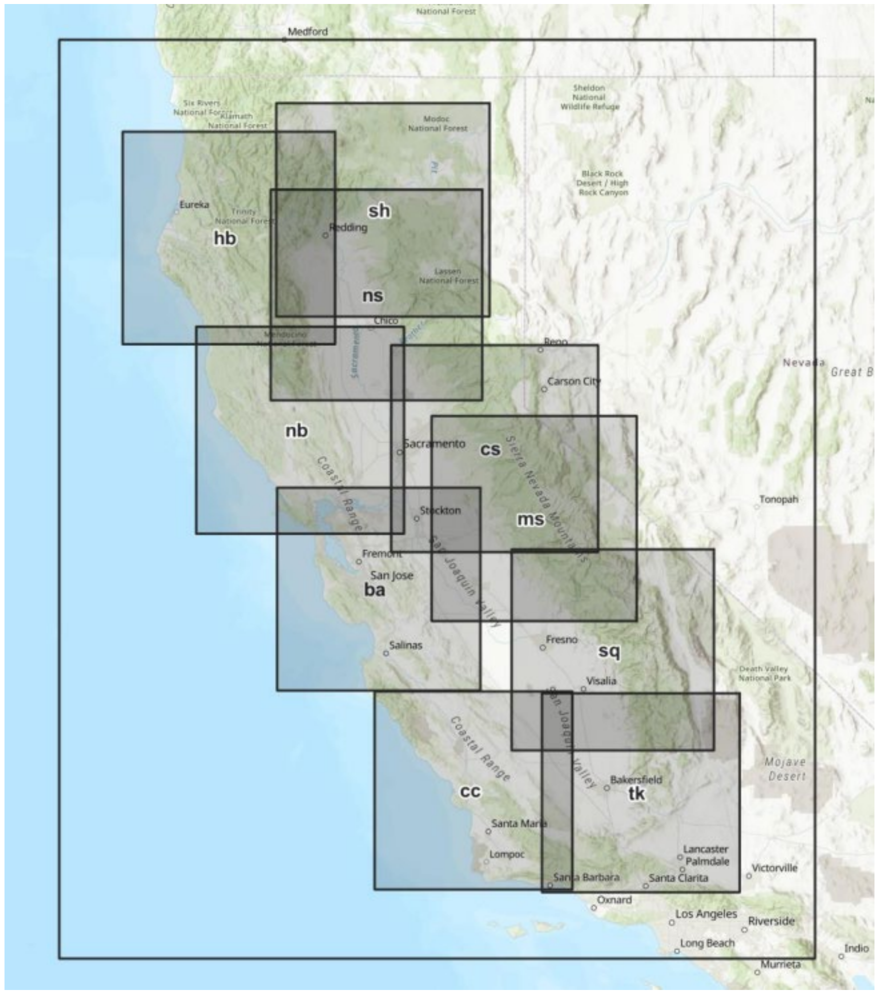
Below is an example of our nested domain configuration with nested grids, in Figure PG&E-10.5.1-1 and Figure PG&E-10.5.1-2.

FIGURE PG&E-10.5.1-1:
DIAGRAM OF NESTED DOMAIN CONFIGURATION WITH NESTED GRIDS



Note: The innermost domain covers the entire PG&E service territory with a 2x2 km grid cell lattice.

FIGURE PG&E-10.5.1-2:
DIAGRAM OF NESTED 0.67 KM NESTED DOMAIN CONFIGURATION WITHIN 2 KM DOMAIN



Time Horizon of the Weather Forecast Throughout the Service Territory

The weather forecast has a time horizon of 129 hours (>5 days). This provides a longer lead-time than publicly-available high-resolution models, like the NOAA – High Resolution Rapid Refresh, for more advanced PSPS notifications.

10.5.2 Known Limitations of Existing Approach

The electrical corporation must describe any known limitations of its existing modeling approach resulting from assumptions, data availability, and computational resources. It must discuss the impact of these limitations on the modeling outputs.

Running high-resolution models and ensembles is computationally expensive to perform for a large service territory and requires a large amount of storage.

- Each day, we receive approximately 1.4 terabytes of weather forecast data from our high-resolution model. This data is in addition to ingesting and processing additional external sources of model data from several sources (e.g., American, European, Canadian global models, American high-resolution models, Technosylva, etc.), and does not factor in our high resolution DFM and LFM models, or climatological datasets, which are also produced hourly at 2 x 2 km resolution.
- To cover our entire service territory, our 2 x 2 km domain consists of 396 grid cells along the west-east dimension and 480 along the north-south dimension, for a total amount equaling 190,080 (396 X 480) 2 x 2 km grid cells.
- There is a total of 24 high resolution simulations completed each day (four times per day for the GFS control run and two times per day for the ECM control run and nine members of the ensemble, which is also run 2 times per day). Each simulation generates 190,080 data points (1 per grid cell) every hour out 129 hours available in the forecast. Thus, for a single variable, like temperature, there are 588,487,680 data points generated per day (190,080 grid cells X 24 runs/day X 129 hours/run). There are 15 variables output at the surface, and 51 vertical levels (z) with output as well. Not counting output from the 51 vertical levels, there are approximately 9 billion data points output each day at the near surface alone. If our model resolution increased from 2 x 2 km to 1 x 1 km, this would quadruple the output and increase costs by 620 percent per model run. If we increased our existing model resolution to achieve the highest possible score from the 2023 maturity survey, 100 meters, the output would increase by a factor of 400.

We are limited by computer costs, storage costs and financial costs to run more and more granular dynamic weather models that are physics-based. As AI and machine learning matures in numerical weather prediction, we may be able to achieve higher resolution forecasts at a greater cost-efficiency.

Forecast Accuracy

As weather is a non-linear, chaotic system, we are limited in our ability to perfectly forecast weather, a limitation that has been well documented in the scientific literature. For example, a paper on chaos and weather prediction from the European Centre for Medium-Range Weather states that:

> A requirement for skillful predictions is that numerical models can accurately simulate the dominant atmospheric phenomena. The fact that the description of some physical processes has only a certain degree of

accuracy, and the fact that numerical models simulate only processes with certain spatial and temporal, is the second source of forecast errors. Computer resources contribute to limit the complexity and the resolution of numerical models and assimilation—since, to be useful, numerical predictions must be produced in a reasonable amount of time.

These two sources of forecast errors cause weather forecasts to deteriorate with forecast time. Initial conditions will always be known approximately, since each item of data is characterized by an error that depends on the instrumental accuracy. In other words, small uncertainties related to the characteristics of the atmospheric observing system will always characterize the initial conditions. Consequently, even if the system equations were well known, two initial states, only slightly differing, would depart one from the other very rapidly as time progresses.

10.5.3 Planned Improvements

Tracking ID: SA-16; SA-17

The electrical corporation must describe its planned improvements in its weather forecasting systems. This must include any plans for the following:

- *Increase in model validation;*
- *Increase in spatial granularity;*
- *Decrease in limitations by removal of assumptions;*
- *Increase in input data quality; and*
- *Increase in related frequency.*

Increase in Model Validation

We will utilize an internally developed tool to perform model validations. We expect an increase in models equipped with ML or AI to become available and plan to evaluate some of these models before consideration of operational deployment. See SA-16 and SA-17 in Section 10.1.2 and Table 10-1.

Increase in Spatial Granularity

There are currently no planned increases in the granularity of the core weather model due to costs. However, we may evaluate higher-resolution models derived with ML or AI during this WMP cycle should they become available, which is not known at this time.

Decrease in Limitations by Removal of Assumptions

There are currently no plans to decrease limitations by removing assumptions.

Increase in Input Data Quality

There are currently no plans to increase input data quality.

Increase in Related Frequency

There are currently no plans to increase related frequency.

10.5.4 Evaluating Activities

The electrical corporation must describe its procedures for the ongoing evaluation of the efficacy of its weather forecasting activity (program).

We partnered with two external numerical weather prediction experts to build out and run our high-resolution weather model capabilities. This configuration allows for cross-validation and testing of model results. One vendor was selected as the partner to operationally run the model on the AWS cloud. This vendor has extensive experience building and running the WRF model for several partners around the world. The other vendor selected has extensive model expertise, especially in California, and has worked extensively with other California utilities to build custom model solutions for their operations. This second vendor was selected as the vendor to perform validation and provide expertise and guidance on the optimal model configuration for testing. PG&E also has experts in meteorology, data science and numerical weather prediction on staff who perform ongoing evaluation of the weather forecasting program as well.

These internal and external experts meet regularly to discuss current capabilities and opportunities for future enhancements. In addition, we openly share our model data with the San Jose State Wildfire Interdisciplinary Research Center and make outputs available to the public at the following link: http://www.met.sjsu.edu/weather/wirc-prod/. Our model framework and results were also published via a peer-reviewed process (Carpenter et al., 2024).

10.5.5 Weather Station Maintenance and Calibration

Tracking ID: SA-18; SA-19

In this section, the electrical corporation must provide a narrative describing maintenance and calibration and risk impacts due to weather station inoperability. The narrative should be no more than one page and include the following:

- *Acceptable percentage of weather station outages as defined by the electric corporation;*
- *Justification for how reduced coverage does/does not impact risk to PSPS decision making and any methods to reduce those impacts;*
- *Any limitations to conducting annual maintenance and calibrations (such as staffing, training, terrain, access, etc.):*

- *This must include the number of incomplete maintenance or calibration events for weather stations in the last calendar year; and*

- *A description of what efforts are in place to ensure acceptable levels of weather station coverage throughout the electric corporation's service territory.*

PG&E has a dedicated program to track calibration and maintenance of stations in our weather station network. Before installation, each weather station instrument is factory calibrated to ensure quality data is collected once deployed. During installation, field technicians work with analysts from an external vendor to ensure proper data communication before leaving the site. As discussed below, we have both automated and routine processes during the operational phase of each station to ensure data quality.

Routine Calibration After Installation

Our goal is to perform a site calibration of each weather station once per calendar year and within 15 months of its last calibration. If the station is operational and without error, no maintenance is performed. If the station is not operational or falls outside of the manufacturer's standard, we perform any maintenance or replace equipment, as necessary. The calibration is not marked complete until all instruments are operational, without error. Site calibrations are done using calibration kits supplied by a vendor, which are also calibrated once per year.

Mitigations

If any station goes beyond 15 months since its last calibration due to any reason, the station is considered out of compliance with PG&E's internal calibration guidelines and is blacklisted by PG&E meteorology by marking the station as "untrusted" in internal databases. An untrusted status removes the weather station and live data from situational awareness systems involved in PSPS until calibration or maintenance is completed and the station can be toggled back to "trusted" status. Weather station parts/components can and will fail outside routine maintenance cycles, and we have a process to identify, assign, track and perform emergent maintenance. Our external vendor collects data from each station every 10 minutes and processes it through a system of automated data and station health checks (e.g., battery voltage, range, and reasonableness checks). Alerts are generated for any anomalies and are verified by an external analyst. After verification, these alerts are sent to our Enterprise Network Operations Center, where an internal incident ticket is generated and assigned to the local telecom yard and technician for resolution. These trouble tickets are typically generated due to low or dead batteries, inconsistent or dead modems/comms, bad/dead datalogger, or suspect data. In some cases, we find stations vandalized (e.g., gunshots). In the case of suspect data, we blacklist the station by marking the station as "untrusted" in internal databases until sensors have been replaced.

Acceptable Percentage of Weather Station Outages

Our annual target is that by October 1 each year, before the traditional peak of PSPS season, 95 percent of stations in the network are in “trusted” status. See SA-18 in Table 10-2, Section 10.2.1.

Mitigating the Impact of Reduced Coverage on PSPS Decision-making

Loss of weather station data can be impactful to PSPS decision-making depending on how many stations are lost versus the existing coverage of sites in proximity to a PSPS event. We mitigate the loss of individual weather stations by utilizing other weather stations in an area, utilizing gridded wind initialization fields, such as the real-time mesoscale analysis from NCAR, and using a variety of internal and external forecast data. The weather station project team monitors the calibration and maintenance of each station versus our plan for the year to help ensure targets are met. In addition, we can expedite repairs if a critical event is coming, and if we absolutely need a specific weather station to monitor conditions. The “trusted” station coverage is evaluated before an event in the EOC and any station calibration escalations are handled through the operations unit of the emergency response team. As a last resort, we can deploy field resources to take live measurements and observations in the field if observations are lacking in a critical area or use live camera data from the Alert California network to monitor tree movement or line sway.

Limitations to Conducting Annual Maintenance and Calibrations

Due to the remote nature of many of the weather stations in the service territory, there are times when safe access via the required equipment (bucket truck) is no longer possible. Typically, this is due to road degradation, vegetation hazards, heavy snow caused by the previous winter, and customer refusals. We work with internal and external parties on each case to allow safe access. If we cannot resolve the issue, we mark the calibration record as a “Can’t Get In.” We continue attempts to resolve the access issue working with internal and external parties as needed. If we are unable to resolve the access issue, we evaluate relocating the station to another area.

Incomplete Maintenance or Calibration Events

In calendar year 2024, we were unable to complete calibration or maintenance on 27 weather stations versus 1,502 successful calibrations. Please see ACI PG&E-23-23 – Weather Station Maintenance and Calibration for more information including a table and reason each site could not be calibrated.

Efforts to Ensure Acceptable Levels of Weather Station Coverage

While the PG&E weather stations network is fully mature, we plan to incrementally install additional stations through the WMP cycle to bolster situational awareness. At least once per year, the lead meteorologist assigned to locate stations through the service territory meets with meteorology leadership to discuss the priority of locations that should be targeted. These locations are identified through a Geographic Information System (GIS) distance analysis of how far each line mile is away from a weather station, as well as any lessons learned from PSPS events the prior season.

10.6 Fire Potential Index

The electrical corporation must describe its process for calculating its FPI or a similar a landscape-scale index used as a proxy for assessing real-time risk of a wildfire under current and forecasted weather conditions.[179] *The electrical corporation's description must include the following:*

- *Its existing calculation approach and how its FPI is used in its operations;*
- *The known limitations of its existing approach;*
- *Implementation schedule for any planned changes to the system; and*
- *The electrical corporation must reference the Tracking ID where appropriate.*

In this section we describe our approach for calculating our FPI model used for determining real-time risk of wildfires under current and forecasted weather conditions. The FPI Model is driven largely from weather forecasts and will have similar limitations discussed in Section 10.5.

10.6.1 Existing Calculation Approach and Use

The electrical corporation must describe:

- How it calculates its own FPI or if uses an external source, such as the United States Geological Survey (USGS);[180]
- Assumptions in calculations and justification for each assumption; and
- How it uses its or an FPI in its operations.

Additionally, if the electrical corporation calculates its own FPI, it must provide tabular information regarding the features of its FPI.

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[179] *Pub. Util. Code § 8386(c)(3).*

[180] *USGS Fire Danger Map and Data Products Web Page (accessed Oct. 27, 2022): https://firedanger.cr.usgs.gov/viewer/index.html.*

Summary

The FPI is a PG&E model developed to understand the potential for large and catastrophic fires to occur across the PG&E service territory. The first FPI was developed in 2015 and has been enhanced significantly over several iterations since. The latest model iteration model is called the FPI 5.0 model, which is Version 5 and the most accurate model to date.

FPI informs operational decision making of PSPS and EPSS and informs crews what precautions must be taken to reduce the risk of fires as directed by utility standards. FPI is also a key input into the consequence formulation of PG&E's planning models (Wildfire Distribution Risk Model (WDRM), WRTRM) that inform key long term wildfire risk programs of undergrounding and system hardening prioritization. Improvements in FPI model accuracy allows for greater operational mitigation of utility caused wildfire risk through PSPS and EPSS for a given customer impact, and better strategic prioritization of undergrounding and other wildfire risk mitigations.

Below is a short history on the evolution of FPI models since 2015 that showcases PG&E's continuous improvement efforts through multiple WMP cycles.

PG&E received daily fire danger ratings directly from external sources up until December 31, 2014, when the service was disabled at the external source. In 2015, PG&E evaluated multiple public sources and methodologies for fire danger rating and benchmarked with SDG&E on their deployment of an FPI using high-resolution weather and fuel model data. In addition, PG&E scientists took instructor-led advanced courses in fire danger rating offered by the National Wildfire Coordinating Group to understand agency best practices and methodologies to evaluate fire danger. The early development work of FPI and Numerical Weather Prediction (POMMS project) is discussed in detail in PG&E's Electric Program Investment Charge (EPIC) 1.05 project report.[181] This led to the Version 1 FPI model, which leveraged the National Fire Danger Rating System (FPI 1.0).

In 2018, PG&E produced FPI 2.0, which was an index-based model that combined weather, fuels and a green-up component called the enhanced vegetation index. Its formulation was closely modeled after SDG&E's FPI and valuable benchmarking with SDG&E meteorologists and scientists.

FPI 3.0 was produced in 2019 by coupling the weather and fuels data around the ignition of each fire in the USFS's Fire Program Analysis – Fire-Occurrence Database (FPA-FOD). This was the first iteration of a machine learning model that used historical fire occurrence data with a logistic regression framework. The end goal was to create an FPI model that could predict, based on forecasted weather and fuels conditions, the probability of a large fire given an ignition instead of an FPI index value related to the risk. The 2019 FPI model was a function of several quantifiable factors: the LFM, the Nelson DFM 10 hour, the Fosberg Fire Weather Index and Land Use.

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181 PG&E's Electric Program Investment Charge 1.05 Project Report, available at: https://www.pge.com/assets/pge/docs/about/corporate-responsibility-and-sustainability/PGE-EPIC-Project-1.05.pdf.

The FPI 4.0 model was deployed in August 2021 and operated through July 31, 2024. It leveraged a novel machine learning framework, additional model features and a fire occurrence dataset developed by Sonoma Technology. Data scientists, meteorologists, and fire scientists tested dozens of new model features and various models. Among the model-types tested were logistic regression and multiple machine-learning classification model types. Model results were tested using a train-test split ratio of 70 percent-30 percent. The 4.0 model is discussed in detail in PG&E's 2022 and 2023 WMP public filings.

During each iteration, the goal has been to increase FPI accuracy by testing additional model features, model frameworks (e.g., logistic regression versus more advanced machine learning models such as decision trees and gradient boosting) and improving or creating input datasets. The sections below discuss improvements made across these elements for FPI 5.0

The FPI 5.0 model was developed in 2022 and 2023 and approved for operations starting August 2024 and has several enhancements and improved skill over FPI 4.0. The key enhancements include:

- Addition of fire radiative power (McClure, *et. al.,* 2023) for FPI classes to better identify catastrophic fires based not only by rapid growth, but also high intensity, which is found to be key to explaining fires resulting in structure loss and more likely to escape containment;

- Expanded model training data to use all detects rather than only the first fire detect, this required careful consideration of formulation of sample weights used in model training based on the detection order to weight earlier detects more than later detects;

- Improved spatial relations of weather, fuel moisture, fuels, and terrain data by spatially relating satellite fire detection polygon shapes with model data rather than using points to represent fires;

- Finer spatial resolution of 0.7km^2 hexagons to capture greater detail of terrain and fuel categories compared to the previous 2x2 km (4 km^2) grid cell aggregation of fuels and terrain;

- Improved temporal resolution and coupling of satellite fire detected fire growth and temporal relations to weather and fuel moisture features by using Governance Oversight Execute Support (GOES) detects when available; and

- New weather and fuel moisture input features including soil moisture, enhanced dead and LFM models, new herbaceous fuel moisture model, solar radiation, and new fuel properties features added including fuel bed depth and fuel complexity.

The FPI model is trained on a novel fire occurrence dataset (McClure et al., 2023)[182] that combines sub-daily to hourly fire growth from satellite fire detections from Visible Infrared Imaging Radiometer Suite (VIIRS) and GOES where available with agency fire information. The FPI model combines fire weather, dead and LFM, topography and fuel types to predict the probability of small, large, critical or catastrophic fire potential.

The weather and fuel moisture features are sourced from PG&E's 30+ year down-scaled climatology available hourly at a 2x2 km resolution, referenced earlier in this document. The fuel categories and topography features from Technosylva are aggregated to a new finer spatial resolution of 0.7km^2 hexagons using the h3 opensource framework developed by Uber.

Calculating the FPI and Model Assumptions

The FPI model is based on a multi-classification balanced random forest framework, a state-of-the-art open-source machine learning model based on decision trees.

FPI is trained on a novel fire occurrence dataset (McClure *et. al.,* 2023) that combines agency fire information with satellite fire detections. Fire detections are derived from satellite infrared data and provide information on the location, intensity and time of fires. FPI v5.0 was trained on satellite fire detections using defined classes that separate small, moderate, critical, and catastrophic defined fires. These classes are determined by both fire spread and intensity. For example, a slow moving, low intensity fire would be defined as small, while a fast moving, intense fire would be defined as catastrophic. Historical fire information, such as impacts and consequences, were used to define these classes.

The class breakpoints are shown in the table below based on if the detect interval was less than or greater than 3 hours. Note that the class names pertain to the FPI definition only and should not be confused with the Office of Energy Infrastructure Safety definition of Catastrophic Fire.

Table PG&E-10.6.1-1 below summarizes our FPI Class Breakpoints.

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182 McClure et al., *Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations*, International Journal of Wildland Fire (Apr. 3, 2023), available at: https://www.publish.csiro.au/wf/fulltext/WF22048.

TABLE PG&E-10.6.1-1:
FPI CLASS BREAKPOINTS

FPI Class	VIIRS Growth (Acres), Fire Radiative Power (Megawatts (MW)) (<3 Hours Between VIIRS Detects)	VIIRS Growth, Fire Radiative Power (MW) (>=3 Hours Between VIIRS Detects)
Small	<70 acres	<70 acres
Large	<200 acres OR <200 MW	<200 acres OR <200 MW
Critical	<2,000 acres OR <2,000 MW	<7,000 acres OR <7,000 MW
Catastrophic	>=2,000 acres & >=2,000 MW	>=7,000 acres & >=7,000 MW

The fire occurrence data is sampled from polar-orbiting satellites that scan the surface of Earth in a whisk-broom manner along swaths. We found two modes of detection between scans due to the lag time between VIIRS instruments on satellites Suomi-NPP and NOAA-20, as well as limb and nadir detections. Thus, to utilize the most fire occurrence data, we classify two sets of breakpoints based on time between detections with final values being derived via a grid search. Essentially, high intensity and fast spreading fires are classified as catastrophic for FPI training purposes.

Fire intensity provided in MW is related to the satellite detected fire radiative power which is an additional observed dimension to acres burned to understand fire dynamics. Analyzing fire radiative power of historical fires, we find fires with higher fire radiative power are more likely to escape containment and result in building losses.

Table PG&E-10.6.1-2 below presents how consequences from historic fires are distributed in these four classes across the lifespan from initiation, the first 24 hours and through the extended burning period. Most building losses occur in the first 24 hours in the catastrophic class, with very few losses occurring in the moderate and small classes.

TABLE PG&E-10.6.1-2:
FIRE CONSEQUENCE DISTRIBUTION BY CLASS BREAKPOINTS

	% of Total Buildings Damaged				Buildings Damaged per 10,000 Acres			
FPI Class Actual	**Small**	**Large**	**Critical**	**Catastrophic**	**Small**	**Moderate**	**Critical**	**Catastrophic**
Initial Detect	0.0%	0.8%	4.6%	30.8%	2	6	78	683
Initial Burning Period (0+ to 24+ hours)	0.0%	1.2%	3.7%	31.1%	–	19	36	392
Second Burning Period (24+ to 72+ hours)	0.0%	0.0%	3.4%	8.0%	–	1	26	69
Third Burning Period (3+ to 7+ days)	0.0%	0.2%	4.4%	2.6%	–	3	19	29
Extended Burning Period (More than 7+ days)	0.0%	0.0%	1.0%	8.2%	–	–	2	34

The FPI model increased from a 3-class to a 4-class model with the addition of a new Critical fire class. The Catastrophic fire class focuses more on wind driven fires, and the new Critical fire class focuses more on fuel and terrain driven fires.

The mean final fire size of those fires with a first detect with these classifications are as follows:

- Small: approximately 300 acres;
- Large: approximately 1,500 acres;
- Critical: 20,000 acres; and
- Catastrophic: ~80,000 acres.

The FPI model is output hourly for each 0.7km2 hexagon with features of hourly weather and fuel moisture, fuel types and terrain as input.

$$P(FPI_{class,hexagon,hour}) = f(features_{hexagon,hour})$$

PG&E tested over 160 features in an iterative process to train the FPI5.0. PG&E used model skill, feature exploratory and correlation analysis and machine learning interpretability tools including various feature importances and shapely additive explanations to select the final model features for operations. More than 70 formulations of FPI were trained and evaluated in an iterative process to optimize model skill, model interpretability, explainability and operability.

The FPI model improved the spatial relations of weather, fuel moisture, fuels, and terrain model data with fire data by using VIIRS Satellite Fire Detection polygon shapes.

Further, the temporal relations of fire growth and model data are also improved by using GOES satellite fire detection hourly derived growth between VIIRS detects. The FPI 5.0 model shows improved skill across all fire classes compared to the previous FPI 4.0 model. Table PG&E-10.6.1-3 below summarizes our FPI model skill score comparison.

TABLE PG&E-10.6.1-3:
FPI MODEL SKILL SCORE COMPARISON

Fire Class	FPI 4.0 Model Receiver-Operating Characteristic Curve (ROC) Area Under the Curve (AUC)	FPI 5.0 Model ROC AUC
Catastrophic	0.88	0.95
Critical	Class Not Used	0.88
Large	0.55	0.62
Small	0.68	0.73
Macro-Average ROC AUC	0.70	0.83

32 features were selected in the final FPI model for operations, which are summarized and presented in the figures and tables below. The FPI 5.0 model features include:

- Weather features of wind speed, turbulence, temperature, and vapor pressure deficit;
- New Normalized Difference Vegetation Index herbaceous fuel moisture model and enhanced existing dead, herbaceous and woody fuel moisture models;
- Topography features including terrain ruggedness and slope;
- New soil moisture and solar radiation features;
- Improved fuel categories;
- New fuel properties features including fuel bed depth and fuel complexity; and
- The fuel categories, fuel properties and topography features are aggregated to the 0.7 km_2 hexagons from the underlying 30 m resolution.

Table 10-5 below summarizes FPI model features.

TABLE 10-5:
FIRE POTENTIAL INDEX MODEL FEATURES

Feature Group/ Feature (Predictor)	Altitude	Description	Source	Update Cadence	Spatial Granularity	Temporal Granularity
TerrainRugged_Mean	surface	Measure of terrain ruggedness in each h3 hexagon	DEM	N/A	10m	N/A
Slope_Degree_Mean	surface	Measure of slope in each h3 hexagon	DEM	N/A	10m	N/A
Fuels: Grass	300 m	Proportion of fuel category in h3 hexagon cell attributed to grass	Technosylva	Annual	30m	N/A
Fuels: Grass Shrub	surface	Proportion of fuel category in h3 hexagon cell attributed to grass shrub	Technosylva	Annual	30m	N/A
Fuels: Shrub	surface	Proportion of fuel category in h3 hexagon cell attributed to shrub	Technosylva	Annual	30m	N/A
Fuels: Timber Litter	surface	Proportion of fuel category in h3 hexagon cell attributed to timber litter	Technosylva	Annual	30m	N/A
Fuels: Timber Understory	surface	Proportion of fuel category in h3 hexagon cell attributed to timber understory	Technosylva	Annual	30m	N/A
Fuels: Urban Roads Agg Low Burnable	surface	Proportion of fuel category in h3 hexagon cell attributed to dense urban, roads, or agriculture land	Technosylva	Annual	30m	N/A
Fuels: Urban Roads Agg High Burnable	surface	Proportion of fuel category in h3 hexagon cell attributed to urban, roads, or agriculture land adjacent or surrounded by burnable fuels	Technosylva	Annual	30m	N/A
fuel_bed_depth_ft	surface	The fuel bed depth from fuel model classes	Technosylva	Annual	30m	N/A
ave_fuel_complexity	surface	The average fuel complexity derived from fuel model data	Technosylva	Annual	30m	N/A
dfm_1000hr	surface	The moisture content in the 1,000 hr. dead fuel model class	POMMS & Technosylva	2x per day	2km	hourly
dfm_100hr	surface	The moisture content in the 100 hr. dead fuel model class	POMMS & Technosylva	2x per day	2km	hourly
dfm_10hr	surface	The moisture content in the 10 hr. dead fuel model class	POMMS & Technosylva	2x per day	2km	hourly

TABLE 10-5:
FIRE POTENTIAL INDEX MODEL FEATURES
(CONTINUED)

Feature Group/ Feature (Predictor)	Altitude	Description	Source	Update Cadence	Spatial Granularity	Temporal Granularity
dfm_1hr	surface	The moisture content in the 1 hr. dead fuel model class	POMMS & Technosylva	2x per day	2km	hourly
lfm_chamise_new	surface	The moisture content in the LFM chamise new growth class	POMMS & Technosylva	daily	2km	daily
ndvi	surface	The Normalized Vegetation Index per h3 hexagon	POMMS & Technosylva	Daily	2km	daily
smois_0	5 cm	Moisture content in the soil at a depth of 5 cm	POMMS	2x per day	2km	hourly
vpd_mb_300m	300m	Vapor pressure deficit at 300m	POMMS	2x per day	2km	hourly
vpd_mb_50m	50m	Vapor pressure deficit at 50m	POMMS	2x per day	2km	hourly
vpd2m_mb	2m	Vapor pressure deficit at 2m	POMMS	2x per day	2km	hourly
sfcdownshortwaveflux	surface	Shortwave flux at the surface – solar radiation	POMMS	2x per day	2km	hourly
temp_f_300m	300m	Temperature at 300m above surface in Fahrenheit	POMMS	2x per day	2km	hourly
temp_f_50m	50m	Temperature at 50m above surface in Fahrenheit	POMMS	2x per day	2km	hourly
temp2m_f	2m	Temperature at 2m above surface in Fahrenheit	POMMS	2x per day	2km	hourly
tke_pbl_300m	300m	Kinetic energy per unit mass observed in eddies characteristic of turbulent flow in Joules/kg at 300m	POMMS	2x per day	2km	hourly
tke_pbl_50m	50m	Kinetic energy per unit mass observed in eddies characteristic of turbulent flow in Joules/kg at 50m	POMMS	2x per day	2km	hourly
ustar_frc_vel	2m	Wind shear stress in velocity terms.	POMMS	2x per day	2km	hourly
ws_mph_300m	300m	Wind speed at 300m above surface	POMMS	2x per day	2km	hourly
ws_mph_50m	50m	Wind speed at 50m above surface	POMMS	2x per day	2km	hourly
ws_mph	10m	Wind speed at 10m above surface	POMMS	2x per day	2km	hourly

How We Use the FPI in Operations:

The operational application of FPI is forecast twice per day with hourly fire growth probabilities down to each 0.7 km^2 hexagons with a forecast horizon of 129 hours ahead with fuel moisture and weather inputs from the 8-member ensemble of POMMS, configurations of the WRF model. The same model configuration used to construct the climatology of weather and fuel moistures is utilized in the forecast model application. Strategic applications of FPI are based on PG&E's 30+ year down-scaled weather and fuel moisture climatology, fuel types and terrain down to 0.7 km^2 resolution.

The FPI model is aggregated spatially and temporally depending on the application. For PSPS it is reviewed at its finest resolution at hourly timesteps down to 0.7km^2 hexagons. For EPSS, it is aggregated to daily high fire risk circuit segments to inform daily circuit device protection settings. For other operational mitigations including how crews mitigate ignition risk, FPI is aggregated to daily Fire Index Areas.

10.6.2 Known Limitations of Existing Approach

The electrical corporation must describe any known limitations of current FPI calculation. Specifically, list of any changes implemented since its last WMP submission, including justification of for changes and lessons learned, where applicable.

The FPI model uses a ML random forest framework.

The FPI Model requires the requisite input forecast data as described above to produce a forecast each hour. This high-resolution forecast data is currently available with a ~120 hour forecast horizon. The FPI Model is driven largely from the weather forecasts and will have similar limitations as weather forecasting (see Section 10.5).

10.6.3 Planned Improvements

The electrical corporation must describe its planned improvements for its FPI, including a description of the improvement, reason for the change, and the planned schedule for implementation.

There are no planned improvements for this cycle.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 11

EMERGENCY PREPAREDNESS, COLLABORATION, AND COMMUNITY OUTREACH

11. Emergency Preparedness, Collaboration, and Community Outreach

Each electrical corporation must develop and adopt an emergency preparedness plan in compliance with the standards established by the CPUC, pursuant to Public Utilities Code (Pub. Util. Code) Section 768.6(a).[183]

11.1 Targets

In this section, each electrical corporation must provide qualitative targets for emergency preparedness, collaboration, and community outreach.

The electrical corporation must provide at least one qualitative target for the following initiatives:

- *Emergency Preparedness and Recovery Plan (Section 11.2);*
- *External Collaboration and Coordination (Section 11.3);*
- *Public Communication, Outreach, and Education (Section 11.4); and*
- *Customer Support in Wildfire and PSPS Emergencies (Section 11.5).*

11.1.1 Qualitative Targets

The electrical corporation must provide qualitative targets for its 3-year plan for implementing and improving its emergency preparedness, collaboration and community outreach,[184] *including the following:*

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the Tracking ID(s)used in past WMPs ("Previous Tracking ID"), if applicable;*
- *A completion date for when the electrical corporation will achieve the target; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated.*

PG&E's Qualitative Targets for Emergency Preparedness, Collaboration, and Community Outreach for the 3-Year WMP period are shown in Table 11-1 below.

[183] *Pub. Util. Code § 8386(c)(19).*

[184] *Annual information included in this section must align with the applicable data submission.*

- Reporting: PG&E will use all targets for quarterly compliance reporting including the QDR, QN, and the ARC. We note that throughout this 2026-2028 WMP, we discuss current plans for wildfire-related activities beyond the targets in Table 11-1. The timing and scope of these additional activities may change. We will not be reporting on these activities in our QDR, QN, or ARC because they are not defined targets but are descriptions of plans and activities in our 2026-2028 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All targets are subject to External Factors. External Factors in this context are reasonable circumstances that may impact execution against targets, including, but not limited to, physical conditions, environmental delays, landowner or customer refusals or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, active wildfire, exceptions or exemptions to regulatory/statutory requirements, and other safety considerations.

- Utility Initiative Tracking IDs (Tracking IDs): We are including Tracking IDs in each section that has associated targets. Table 11-1 displays the Tracking IDs we are implementing to tie the targets to the narratives in the WMP. The Tracking IDs will also be used for reporting in the QDR.

- HFTD, HFRA, Buffer Zone Areas: Unless stated otherwise, all targets either involve work or audits on units or equipment located in, traversing, or energizing HFTD, HFRA, or Buffer Zone areas or involve units or equipment in HFTD, HFRA, or Buffer Zone areas.

TABLE 11-1:
EMERGENCY PREPAREDNESS AND COMMUNITY OUTREACH TARGETS BY YEAR

Initiative	Activity (Tracking ID #)	Previous Tracking ID, if Applicable	2026 End of Year Total/Completion Date	2027 Status	2028 Status	Section; Page Number
Public Communication, Outreach, and Education Awareness	Outreach to HFRA Infrastructure Customers (CO-04)	CO-04	Completed; September 30, 2026	Completed; September 30, 2027	Completed; September 30, 2028	11.4; p. 512
Public Communication, Outreach, and Education Awareness	Outage Preparedness Campaign (CO-05)	CO-05	Completed; September 30, 2026	Completed; September 30, 2027	Completed; September 30, 2028	11.4; p. 512
Emergency Preparedness and Recovery Plan	Common Operating Picture (COP) Technology (EP-07)	EP-07	Started; March 2026	In Progress; December 31, 2027	Completed; December 31, 2028	11.2; p. 486
External Collaboration and Coordination	Continue sharing PSPS lessons learned (PS-10)	PS-10	Completed; December 31, 2026	Completed; December 31, 2027	Completed; December 31, 2028	11.3; p. 501
Customer Support in Wildfire and PSPS Emergencies	Access and Functional Needs (AFN) Customer Support During PSPS Emergencies (PS-12)	N/A	Started; April 2026	In Progress; 2027	Completed; December 31, 2028	11.5; p. 537

11.2 Emergency Preparedness and Recovery Plan

In this section, the electrical corporation must provide an overview of how it has evaluated, developed, and integrated wildfire- and PSPS-specific emergency preparedness strategies, practices, policies, and procedures into its overall emergency plan based on the minimum standards described in GO 166.[185] *The electrical corporation must provide the title of and link to its latest emergency preparedness report, the date of the report, and an indication of whether the plan complies with CPUC Rulemaking (R.) 15-06-009, Decision (D.) 21-05-019, and GO 166. The overview must be no more than two paragraphs.*

In addition, the electrical corporation must provide a list of any other relevant electrical corporation documents that govern its wildfire and PSPS emergency preparedness planning for response and recovery efforts. This must be a bullet point list with document title, Version (if applicable), and date. For example:

- *Electrical Corporation's Emergency Response Plan (ECERP), Third Edition, dated January 1, 2021.*

The electrical corporation must reference the Tracking ID where appropriate.

Tracking IDs: EP-07

PG&E's Emergency Preparedness and Response (EP&R) organization is responsible for emergency preparedness, prevention, response, mitigation, and recovery. This includes responding to wildfire incidents and PSPS events. As part of our wildfire and PSPS emergency preparedness efforts, we annually publish the Company Emergency Response Plan (CERP), which describes our organizational structure, actions undertaken in response to emergency situations, and the response structure to fulfill requirements that are scalable to any hazard, including wildfire and PSPS events.

On April 30, 2024, we filed our *GO 166 Report* for the period January 1, 2023, through December 31, 2023. The report complies with the Phase 2 R.15-06-009 rulemaking, which yielded D.21-05-019, and modifications to GO 166.[186] PG&E evaluates, develops, and integrates GO 166 requirements through ongoing threat, hazard, risk, and incident assessments. This helps inform how we conduct training, exercises and After Action Report analyses and how we complete corrective actions aligned with frameworks provided by the National Incident Management System (NIMS),[187] the

[185] *Pub. Util. Code §§ 8386(c)(7), (11), (16), (19), (20).*

[186] GO 166, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M464/K730/464730514.pdf.

[187] FEMA, NIMS, available at: https://www.fema.gov/emergency-managers/nims.

California Standardized Emergency Management System (SEMS),[188] and the NIMS/SEMS component Incident Command System (ICS).[189] Other relevant emergency preparedness plan documents include our *CERP* and supporting annexes. Documents that govern PG&E's wildfire and PSPS emergency response and recovery efforts include:[190]

- PG&E CERP, Version 10, dated November 29, 2024;
- PG&E Wildfire Annex to the CERP, Version 5, dated March 29, 2024;
- PG&E Emergency Communications Annex to the CERP, Version 8, dated June 4, 2024;
- PG&E Electric Annex to the CERP, Version 5, dated July 1, 2024; and
- PG&E PSPS Annex to the CERP, Version 9, dated July 31, 2024.

EP-07 COP Technology sets forth our long-term plan for emergency preparedness. The new integrated operating data will support our emergency response efforts in a single COP tool. We will develop a COP technology to better create situational awareness of ongoing emergencies or hazards, including the availability of necessary resources.

The Federal Emergency Management Agency (FEMA) National Response Framework (NRF) defines a COP as a continuously updated overview of an incident compiled throughout an incident's life cycle from data shared between integrated systems for communication, information management, and intelligence and information sharing. In short, a COP achieves real-time situational awareness across all levels of incident management and jurisdictions for any given emergency incidents. A COP can provide EOCs, incident commanders, and response personnel accurate and timely information concerning equipment distribution, location of personnel, on-site intelligence, and incident mapping when responding to and managing an incident. The NIMS and NRF suggest that agencies develop a COP for responding to a large-scale incident or an incident involving multiple agencies. Specifically, the NRF states that local governments should "gain and maintain situational awareness" in their response actions during a crisis event. Developing a COP system that incorporates advanced technology such as mapping tools, sensors, and video feeds, can improve incident response by

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188 CAL OES, Standardized Emergency Management System, available at: https://www.caloes.ca.gov/office-of-the-director/operations/planning-preparedness-prevention/planning-preparedness/standardized-emergency-management-system/.

189 See Supplemental Information: SEMS, NIMS and ICS, available at: https://www.cdss.ca.gov/dis/res/13Supplemental%20NIMS%20PG.pdf.

190 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

enhancing information sharing, situational awareness, and data transfer during emergency incidents.[191]

11.2.1 Overview of Wildfire and PSPS Emergency Preparedness and Service Restoration

In this section, the electrical corporation must provide an overview of its wildfire- and PSPS-specific emergency preparedness and service restoration plan.[192] The overview must describe the following:

- *Overview of protocols, policies, and procedures for responding to and recovering from a wildfire or PSPS event (e.g., means and methods for assessing conditions, decision-making framework, prioritizations). This must include:*
  - *An operational flow diagram illustrating key components of its wildfire- and PSPS-specific emergency response procedures from the moment of activation to response, recovery, and restoration of service;*
  - *Separate overviews and operational flow diagrams for wildfires and PSPS events;*
- *Key personnel, qualifications, and training that show the electrical corporation has trained the workforce to promptly restore service after wildfire or PSPS event, accounting for workers pursuant to mutual aid agreement or contracts. This must include:*
  - *The key roles and responsibilities, personnel resource planning (internal and external staffing needs), personnel qualifications, and required training programs;*
  - *A brief narrative describing its process for planning to meet its internal and external staffing needs for emergency preparedness planning, preparedness, response, and recovery related to wildfire and PSPS;*
  - *The name of each training program, a brief narrative of the purpose and scope of each training program, the frequency of each training program, and how the electrical corporation tracks who has completed the training program;*
- *Each Memorandum of Agreement (MOA) the electrical corporation has with state, city, county, and tribal agencies within its service territory on wildfire and/or PSPS emergency preparedness, response, and recovery activities. The electrical corporation must provide a brief summary of the MOA, including the agreed role(s) and responsibilities of the external agency before, during, and after a wildfire or PSPS emergency:*

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[191] See Homeland Security Science and Technology, Highlight, *Common Operating Picture for Emergency Responders* (September 2008), available at: https://www.dhs.gov/sites/default/files/publications/CommonOpER_HLT_0908-508.pdf.

[192] *Pub. Util. Code § 8386(c)(16), (19), (20).*

- *Coordination and collaboration with public safety partners (e.g., emergency planning, interoperable communications);*
- *Notification of and communication to customers before, during and after a wildfire or PSPS event; and*
- *Improvements/updates made since the last Base WMP submission.*

The overview must be no more than six pages. The electrical corporation may refer to its emergency preparedness plan to provide more detail. Where the electrical corporation has already reported the requested information in another section of the WMP, it must provide a cross-reference with a hyperlink to that section.

In addition, the electrical corporation must provide a table with a list of current gaps and limitations in evaluating, developing, and integrating wildfire- and PSPS-specific preparedness and planning features into its overall emergency preparedness and recovery plan(s). Where gaps or limitations exist, the electrical corporation must provide a remedial action plan and the timeline for resolving the gaps or limitations.

Overview of Protocols, Policies, and Procedures

PG&E's wildfire and PSPS protocols, policies and procedures for responding to and recovering are governed by PG&E's CERP and associated Wildfire and PSPS Annexes.[193]

- PG&E CERP, EMER-3001M, Version 10, dated November 29, 2024;
- PG&E Wildfire Annex to the CERP, EMER-3105M,Version 5, dated March 29, 2024; and
- PG&E PSPS Annex to the CERP, EMER-3106M, Version 9, dated July 31, 2024.

Operational Flow Diagrams

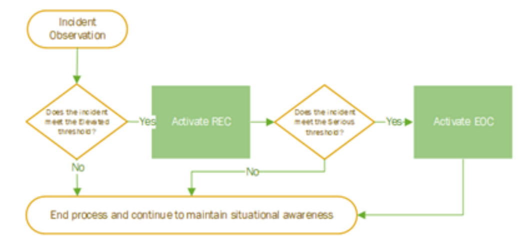
Wildfires scale from the "bottom up," working their way from the company division level Operations Emergency Centers to the Regional Emergency Centers, and then to the Emergency Operating Center (EOC) when certain guidance thresholds are exceeded (e.g., customers outages, etc.).

This is fundamentally different than PSPS events, which are similarly managed out of the EOC, but based on modelled (not necessarily actual) impacts using a "top down," pre-determined "time/places" approach, which dictates the location(s), duration(s) and scale of the event. For details on the difference between these processes see Figure PG&E-11.2.1-1 below.

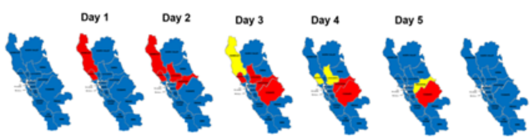
[193] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

FIGURE PG&E-11.2.1-1:
ALL HAZARD INCIDENTS AND PSPS EVENTS PROCESS COMPARISON

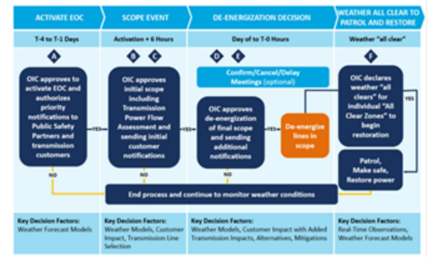
All-Hazard Incidents



Although not always the case, all hazard incidents often expand and contract impacting one or more company divisions to multiple regions over multiple days based on impacts, as shown below. For example, storm related electric customer outages may expand initially on day 1 to 15,000 or more (red), reverting to improved, 10,000 or less (yellow) before returning to normal in each impacted division. PG&E will as conditions allow stage response resources in advance of mutual assistance requirements across company division and regions.



PSPS Events



PSPS events are on the other hand "top down" pre-planned events based on catastrophic fire probability, fire behavior potential, vegetative risk, and electric asset considerations. Time/Place locations and durations (below) are established in advance, with re-energization not occurring until all de-energized lines are assessed.

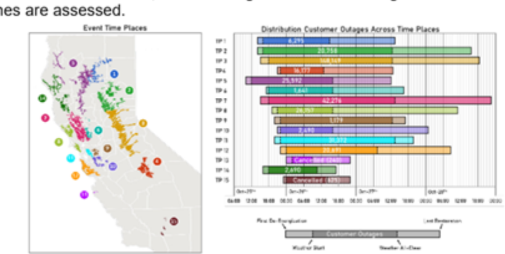


Figure PG&E-11.2.1-2 below explains our decision process for activating PSPS.

FIGURE PG&E-11.2.1-2:
PSPS DECISION PROCESS SEQUENCE

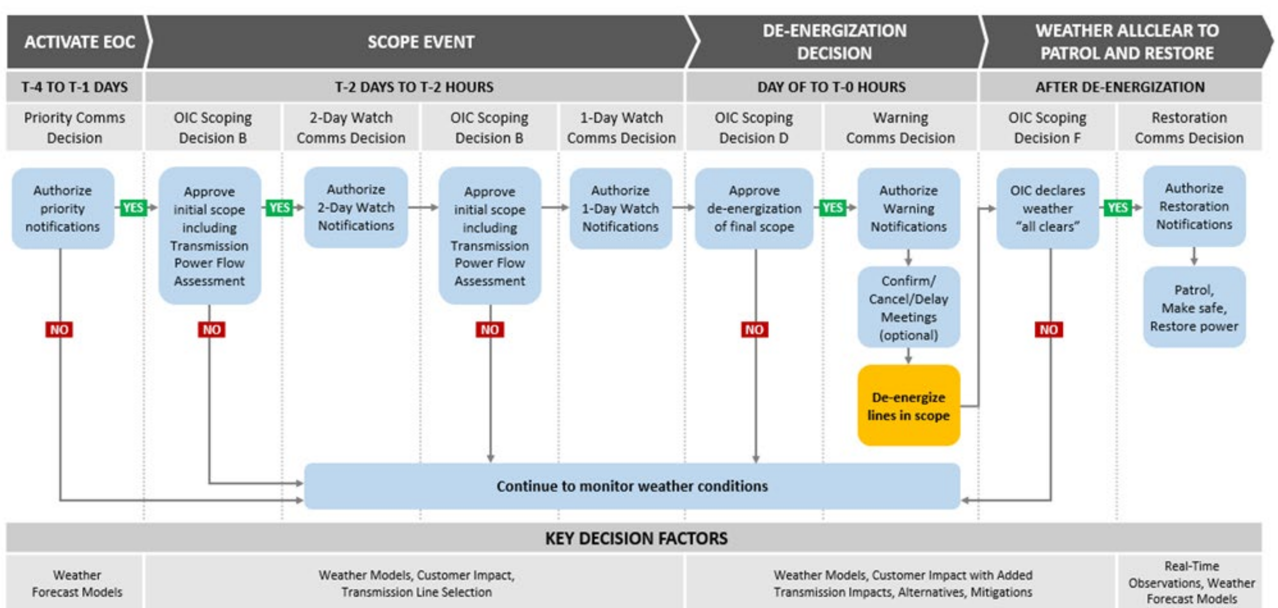
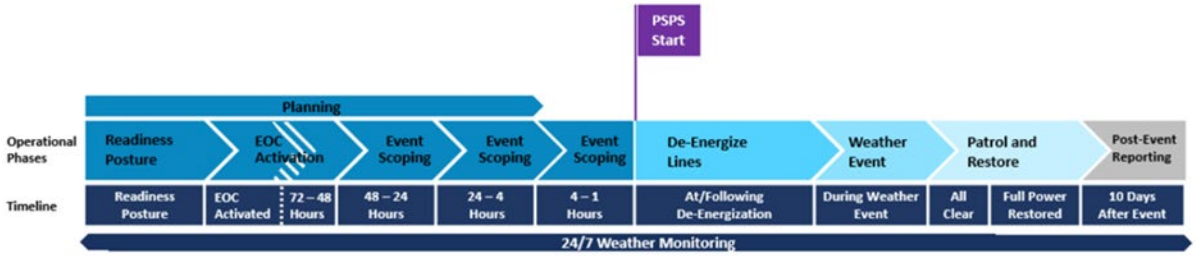


Figure PG&E-11.2.1-3 below explains our PSPS timeline.

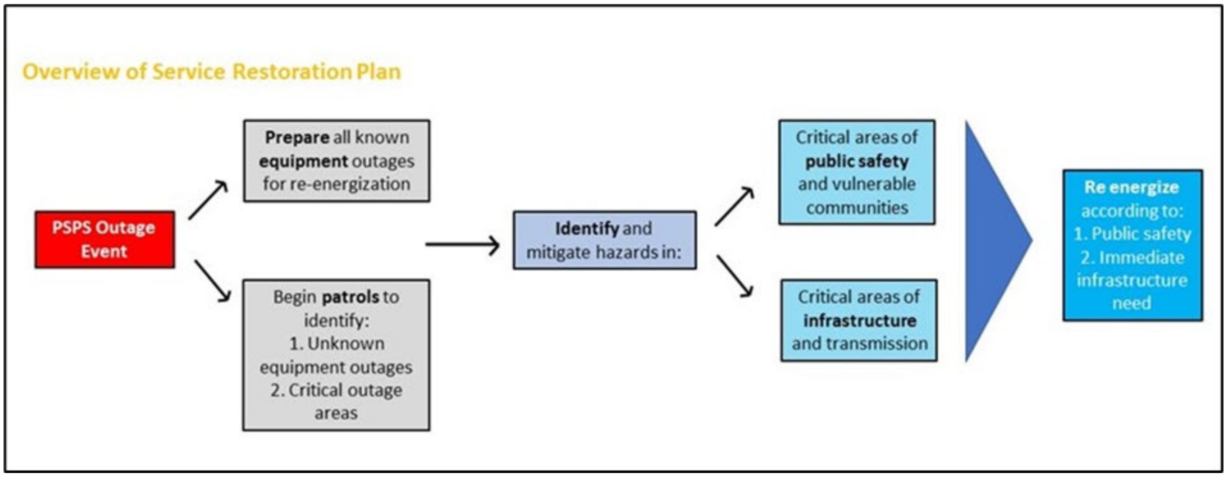
FIGURE PG&E-11.2.1-3:
PSPS TIMELINE



Overview of Protocols, Policies, and Procedures for Service Restoration

Figure PG&E-11.2.1-4 illustrates key components of the service restoration procedures from the start of the PSPS incident to response, recovery, and restoration of service.

FIGURE PG&E-11.2.1-4:
PSPS PROTOCOL AND DECISION FLOW FOR SERVICE RESTORATION PLAN

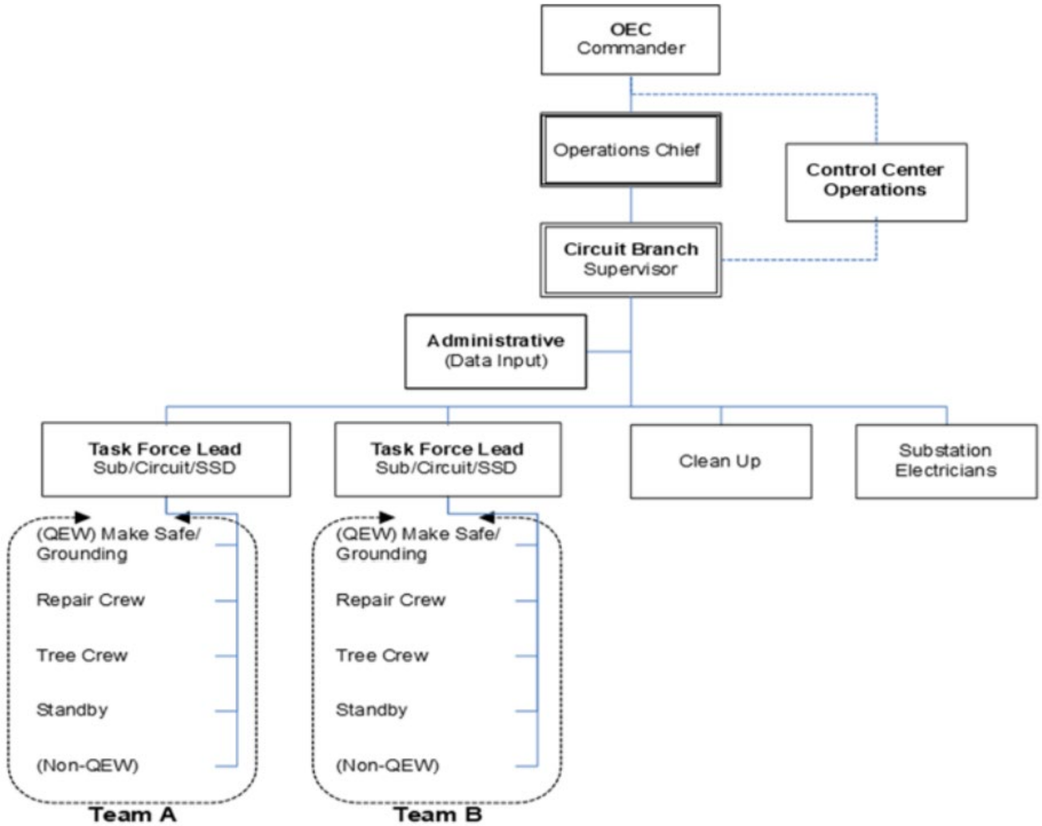


PG&E includes public safety partners in the planning and participation of annual PSPS Tabletop and Functional exercises. Strengths and areas for improvement are captured in an exercise after action report, and corrective actions are leveraged to improve planning and coordination.

For non-PSPS (wildfire) events in accordance with Electric Annex, p. 3-3, PG&E may use a circuit-based strategy designed to improve coordination, assessment, and restoration of highly impacted circuits with multiple cases of trouble. PG&E may also use an order-based or area-based strategy.

Figure PG&E-11.2.1-5 below shows the decision flow for restoring service.

FIGURE PG&E-11.2.1-5:
WILDFIRE PROTOCOL AND DECISION FLOW FOR SERVICE RESTORATION PLAN



Key Personnel, Qualifications and Training

Key Personnel

PG&E's Director of EP&R Response and Operations maintains a rotating 24-hour (day/night) EOC Team schedule with contact information for emergency response key personnel, including, but not limited to the following. This applies to both wildfire and PSPS.

- EOC Commander and the Deputy EOC Commander: Responsible for the overall command of the incident/event; ensuring the safety of all employees involved in the EOC; coordinating readiness of activities related to readiness posture, among others. For additional information on key PG&E EOC personnel roles and responsibilities, please see CERP.

Qualifications

PG&E maintains rigorous qualification standards for wildfire and PSPS emergency personnel who must be trained on the basics of Incident Command System (ICS)[194] to

194 FEMA, ICS Resource Center, available at: http://training.fema.gov/emiweb/is/icsresource/.

be certified to work in one of our EOCs. Depending on their level of responsibility within the EOC, personnel also receive expanded and specialized training to build upon their basic learning.

Training

PG&E has multifaceted training programs for staff that support outages related to wildfires and PSPS that include Emergency Preparedness and Response Training, CERP Training; PSPS-Specific Training; and PSPS Field Personnel Training. EOC personnel are required to take based on their EOC responsibilities:

- IS-100 – Introduction to the Incident Command System, ICS 100;
- IS-200 – Basic Incident Command System for Initial Response, ICS-200;
- IS-700 – An Introduction to the National Incident Management System;
- IS-800 – National Response Framework, An Introduction;
- G606 – Standardized Emergency Management System Introductory Course;
- IS-368 – Including People with Disabilities & Others with Access & Functional Needs in Disaster Operations;
- G-775 – EOC Management and Operations; and
- G-191 – ICS/EOC Interface.

In February 2020, PG&E, California Governor's Office of Emergency Services (Cal OES), the California Public Utilities Commission (CPUC), and the other Investor-Owned Utilities (IOU) entered into a multi-phase Standardized Emergency Management System (SEMS) training agreement to help ensure consistent training requirements for all EOC staff. PG&E has in the years since continued to train EOC staff using an ICS Baseline, Expanded, Advanced, and Position Specific approach.

Resource Planning and Allocation

PG&E uses a relevant and rapid training approach to build and maintain an appropriately sized internal workforce that is in a state of readiness, with skills and abilities to react and respond to any incident within the service territory including both wildfire and PSPS.[195] Where incidents expand beyond the internal resources we have available, we rely upon Mutual Aid Agreements to bring in external utility and contractor resources.

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[195] See CERP Electric Annex, section 7.2, Electric Distribution Training Program, describes training for service restoration. The supporting document is available at: PG&E's Community Wildfire Safety Program.

Drills, Simulations, and Tabletop Exercises

PG&E develops exercises based on regulatory requirements and schedules them by holding a Multi-Year Integrated Preparedness Planning Workshop with all FAs. The dates, type, and scope of exercises are tracked via the Integrated Preparedness Plan. Objectives are defined for each emergency exercise and drill and are tracked accordingly.

Memorandum of Agreement

PG&E does not enter into individual MOAs with tribal, state, city, or county agencies within its service territory. PG&E is in alignment with tribal, city, and state agencies and operates under SEMS and ICS protocols.

Coordination and Collaboration With Public Safety Partners

As part of PG&E's wildfire and PSPS emergency preparedness efforts, we regularly engage with public safety partners at the tribal, state, county, and city levels throughout our service area. Some of our key outreach channels are described below. We follow the engagement standards set forth by the California SEMS.[196]

- Public Safety Specialist (PSS) Team Engagements: Our PSS Team provides personalized engagements (e.g., meetings, calls) with local agencies to discuss and coordinate emergency preparedness. These engagements include: regulatory compliance support; first responder workshops; wildfire safety town halls; Cal OES Mutual Aid Regional Advisory Committees and general regional coordinator meetings; professional group meetings; and trainings, exercises, and drills. During a wildfire emergency or in-scope for a PSPS event, we follow California's SEMS for communicating through county Office of Emergency Services (OES) channels.

- Local Government Forums: We offer to hold an annual meeting to every city and county to discuss our operational plans that could impact emergency planning.

- PSPS Regional Working Groups: We hold quarterly forums to learn about the previous wildfire and PSPS season and share feedback on wildfire safety work; and discuss lessons learned and stakeholder concerns.

- Review of PG&E's Emergency Preparedness Plans: We give local governments an opportunity to conduct a biennial review of our Electric Annex,[197] pursuant to Pub. Util. Code 768.6(b)(1)(c), and in compliance with Standard 10 of GO 166.

- PSS Role: The PSS team supports collaborative communication with public safety partners both during and post-PSPS events and wildfire incidents through one-on-one engagement (law enforcement, fire, Cal OES). Additionally, PSS members have socialized the company's Outage Data Portal with public safety

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196 See Cal OES, Standardized Emergency Management System (SEMS), available at: https://www.caloes.ca.gov/office-of-the-director/operations/planning-preparedness-prevention/planning-preparedness/standardized-emergency-management-system/..

197 The supporting document is available at: PG&E's Community Wildfire Safety Program.

partners, which provides real-time outage information, maps, situational status reports and related outage resources.

- State Operations Centers (SOC) Rep: A PG&E representative is assigned as the primary liaison to the SOC to coordinate community support needs during emergencies either virtually or in-person depending on the event and the SOC needs.

- Tribal Support: Coordinate with tribes, cities, counties, and other agencies to help ensure that the real-time emergency information is provided to tribal government leaders and that their local concerns are addressed and escalated through the emergency management structure as needed.

For PSPS events only, we host the following calls: (1) Public Safety Answer Points or Dispatch Centers when our EOC is first activated; (2) State Executive Briefings with agencies to provide the latest outage and restoration information; (3) Systemwide Cooperators Calls, where Public Safety Partners in the service territory are invited to join and hear the latest event information; and (4) Tribal Cooperator Calls with potentially impacted tribes to provide the latest event information and answer questions in real-time.

Notifications and Communications to Customers

PG&E's processes to notify customers during and after a wildfire or PSPS event are outlined and discussed in CERP[198] and Wildfire Annex[199] and PSPS Annex.[200]

Improvements/Updates Made Since the Last Base WMP Submission.

Since our last WMP, PG&E's preparedness for PSPS events and wildfire emergencies, as well as our coordination with external partners have continued to improve. We continue to challenge our teams and involve outside stakeholders in training and exercise[201] efforts. We benchmark[202] and share PSPS lessons learned with other IOUs monthly, which contributes to our efforts to refine our program.

To ensure consistent, reliable staffing to support colleagues and external partners during PSPS and other EOC activations, since our last Base WMP submission we have created permanent staffing positions for certain key roles. Please see Sections 11.2.1 and 11.3.3 for continuous improvements related to tribal, city, and county collaboration and coordination.

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198 See CERP, Version 10 (Nov. 29, 2024), Section 4.7, Outage Notifications and Reporting, p. 4-8.

199 Wildfire Annex, Version 5 (Mar. 29, 2024), Section 3.6, Customer Outreach, p. 3-8.

200 See PSPS Annex, Version 9.0 (July 31, 2024), Section 7, Customer and Agency Notifications and Resources, p. 7-1.

201 See CERP, Version 10 (Nov. 29, 2024), Section 5.6.3, Exercises. The supporting document is available at: PG&E's Community Wildfire Safety Program.

202 PS-10 Qualitative Target on Continue sharing PSPS lessons learned.

Table 11-2 summarizes our key gaps and limitations in integrating wildfire and PSPS specific strategies into emergency plan.

TABLE 11-2:
KEY GAPS AND LIMITATIONS IN INTEGRATING WILDFIRE- AND PSPS-SPECIFIC STRATEGIES INTO EMERGENCY PLAN

	Gap or Limitation Subject	Brief Description of Gap or Limitation	Remedial Action Plan
Wildfire	After Action Review Trend Analysis	Use of an after-action trend analysis capability across emergency centers, years and incident and event types will enable PG&E to identify repetitive problems impacting response operations.	Strategy: Beginning January 1, 2025, PG&E implemented a critique tool to input after action review hotwash items. This tool will enable trending across emergency centers, years and incident and event types. Target Timeline: Initiated: January 1, 2025 Updated: After EOC activations Reviewed: Annually to identify trends.
PSPS	Errors in Automated Messaging deployment	During a PSPS event, at time of de-energization, the process of deploying notifications to customers about current state of service to their location switches from a manual process with human actions to prep, stage and deploy notifications, to an automated system that is utilized for all outage communications. In certain cases, logic used for normal outage communications interfere with the automation of these messages, causing incorrect notifications, or no notification at all	Strategy: Work with Outage Management Tool (OMT) SME's and program administrators to identify edge cases, like abnormal circuit configurations, mis-mapped customers, and tools put in place to avoid duplicate messages to customers during blue sky outage communications. Target Timeline: Communications around conflicts/issues with OMT Program team began when issue was known. Remedial actions put in place to correct (if possible) at that time. Mis mapped customers reviewed by Operations to correct data for proper transformer assignment at conclusion of each event.
PSPS	Notification Vendor performance	During several events, the vendor used for deploying PSPS notifications mishandled or disregarded files that needed to be processed/delivered, resulting in missed notifications to customers	Strategy: Ongoing dialog with Message Broadcast to identify root causes of missed notifications. Meeting on 12/6/24 with Message Broadcast leadership in San Ramon to discuss notification failures and re-commitment from them to drive errors and miscommunication out of process. Payload testing and drills identified for Spring/Summer 2025 to practice and ensure readiness for PSPS events. Target Timeline: By 7/1/25, conduct exercises and drills to PG&E's satisfaction that file handling and notification deployment will be acceptable to meet PSPS compliance requirements on all notification requirements

11.2.2 Planning and Allocation of Resources

The electrical corporation must briefly describe its methods for planning appropriate resources (e.g., equipment, specialized workers), and allocating those resources to assure the safety of the public during service restoration.[203]

In addition, the electrical corporation must provide an overview of its plans for contingency measures regarding the resources required to respond to an increased number of reports concerning unsafe conditions and expedite a response to a wildfire- or PSPS-related power outage.

This must include a brief narrative on how the electrical corporation:

- *Uses weather reports to pre-position manpower and equipment before anticipated severe weather that could result in an outage;*
- *Sets priorities;*
- *Facilitates internal and external communications; and*
- *Restores service.*

The narrative for this section must be no more than two pages.

PG&E's method for planning appropriate resources and allocating those resources to assure the safety of the public during service restoration is discussed in the CERP.[204]

PG&E maintains three pre-identified Electric Incident Management Teams (IMT). Incident teams, when assembled, have direct authority to plan and execute a response. The three teams may deploy anywhere within the service territory where incident management is needed. Pre-identified IMT increase operational capabilities that are scalable and flexible and ensures adequate continuous coverage.

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[203] Pub. Util. Code § 8386(c)(16), (20).

[204] CERP, Version 10 (Nov. 29, 2024), Section, 3.5.4, Restoration, states as follows: Both Gas and Electric organizations have detailed processes, tools, and technology to develop restoration plans. During any activation, field crews will assess the expected time of restoration based on the current situation and with current resources.

Please see discussion in Section 11.2.1 regarding PG&E's preparedness and response to wildfire and PSPS events.[205] See also CERP,[206] PSPS Annex,[207] and Wildfire Annex.[208]

Uses Weather Reports to Pre-Position Manpower and Equipment

PG&E uses our Distribution System Operation Storm Outage Prediction Project (SOPP) model[209] that our Meteorology team produces to forecast system outages. The SOPP informs staffing for response to PSPS outages; SOPP is used for only for PSPS.

Sets Priorities

PG&E sets priorities based on the level of severity of emergency event.

PG&E has developed a 5-tier incident classification scale that summarizes the severity of an incident and our response to it. The scale ranges from Level 1, which represents a smaller, localized incident, to Level 5, which represents a larger, more complex incident; as described in CERP.[210]

Facilitates Internal and External Communications

PG&E engages in extensive internal and external communications, before, during and after Wildfire and PSPS events as outlined and discussed in the CERP[211] and associated PSPS Annex[212] and Wildfire Annex.

In general, PG&E uses the same internal communication framework for wildfire incidents and PSPS events as the California SEMS Operational Area concept in the context of emergency organizational structure and levels, with emergencies beginning at the local level (Level 1), which is PG&E's base emergency posture.

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205 The supporting documents are available at: PG&E's Community Wildfire Safety Program.

206 See CERP, Version 10 (Nov. 29, 2024), Section 11, Resource Management, Mutual Assistance, and Demobilization, p. 11-1.

207 See PSPS Annex, Version 9 (July 31, 2024), Section 3.5.4, Resource Planning, p. 3-10.

208 See Wildfire Annex, Version 5 (Mar. 29, 2024), Section 4.2, Response Operations, p. 4-13.

209 See CERP, Version 10 (Nov. 29, 2024), Section 5.5.2, Distribution System Operations Storm Outage Prediction Project, p. 5-11.

210 See CERP, Version 10 (Nov. 29, 2024), Section 3.1, The Incident Classification and CERP Section 3.3, Emergency Plan Activation.

211 See CERP, Version 10 (Nov. 29, 2024), Section 4.2, Internal Communication, p. 4-3 and Section 4.4, External Communication, p. 4-5.

212 PSPS Annex, Version 9 (July 31, 2024), Section 7, Customer and Agency Notifications and Resources, p. 7-1.

Restores Service

PG&E uses different electric asset assessment and restoration strategies based on the complexity of each incident.

Wildfire Incidents

PG&E EMER-3001M-CERP, Version 10, Subsection 11.3.1,[213] describe the process the company uses to evaluate incident and event response resource requirements. To determine resource needs, Company Resource Unit Leaders may initially use damage models to align resources with the amount of work that needs to be completed in a particular area. Predictive damage models are used as a starting point for restoration until more accurate assessment information is available from field resource managers. The process is: (1) Repeated throughout the duration of the event; (2) Planned in advance if an impending incident could cause significant damage; and (3) Updated frequently as new restoration or damage model information is received.

PSPS Events

PG&E's restoration protocols for PSPS are outlined in the CERP and PSPS Annex.[214] In general, as Weather All-Clears are issued, restoration crews patrol electrical facilities to identify and repair or clear any damage or hazard before re-energizing. Using the ICS as a base response framework, each circuit is assigned a taskforce consisting of supervisors, crews, troublemen, and inspectors. This structure allows PG&E to patrol and perform step restoration in alignment with the centralized control centers.

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[213] The supporting document is available at: PG&E's Community Wildfire Safety Program.

[214] PSPS Annex, Version 9.0 (July 31, 2024), Section 6.2, Restoration, p. 6-2.

11.3 External Collaboration and Coordination

Tracking IDs: PS-10

PG&E will share PSPS lessons learned and best practices with IOUs through monthly meetings focused on PSPS. The hosting utility will submit a joint working group report that captures the notes from the monthly Joint Utility PSPS Working Group meeting. See PS-10 in Table 11-1 in Section 11.1 for information.

11.3.1 Communication Strategy With Public Safety Partners

The electrical corporation must describe at a high level its communication strategy to inform external public safety partners and other interconnected electrical corporation partners of wildfire, PSPS, and re-energization events as required by GO 166 and Pub. Util. Code Section 768.6.[215] *This must include a brief description of the policies, practices, and procedures the electrical corporation adopts to establish appropriate communication protocols with public safety partners for both wildfire- and PSPS-specific incidents to ensure timely, accurate, and complete communications. The electrical corporation must refer to its emergency preparedness plan as needed to provide more detail. The narrative must be no more than two pages.*

As each public safety partner will have its own unique communication protocols, procedures, and systems, the electrical corporation must coordinate with each entity individually. The electrical corporation must summarize the following information in tabulated format:

- *All relevant public safety partner groups (e.g., fire, law enforcement, Cal OES, municipal governments, Energy Safety, CPUC, other electrical corporations) at every level of administration (state, county, city, or Tribal Nation) as needed;*
- *Key protocols for ensuring the necessary level of voice and data communications (e.g., interoperability channels, methods for information exchange, format for each data typology, communication capabilities, data management systems, backup systems, common alerting protocols, messaging), and associated references in the emergency plan for more details; and*
- *Frequency of prearranged communication review and updates.*

In a separate table, the electrical corporation must list the current gaps and limitations in its public safety partner communication strategy coordination. Where gaps or limitations exist, the electrical corporation must indicate the remedial action plan and the timeline for resolving the gaps or limitations. For all requested information, the electrical corporation must indicate a form of verification that can be provided upon request for compliance assurance.

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[215] *Pub. Util. Code § 8386(c)(19).*

Table 11-3 and Table 11-4 provide the required format and examples of the minimum level of content and detail required.

Communication Strategy for Wildfires

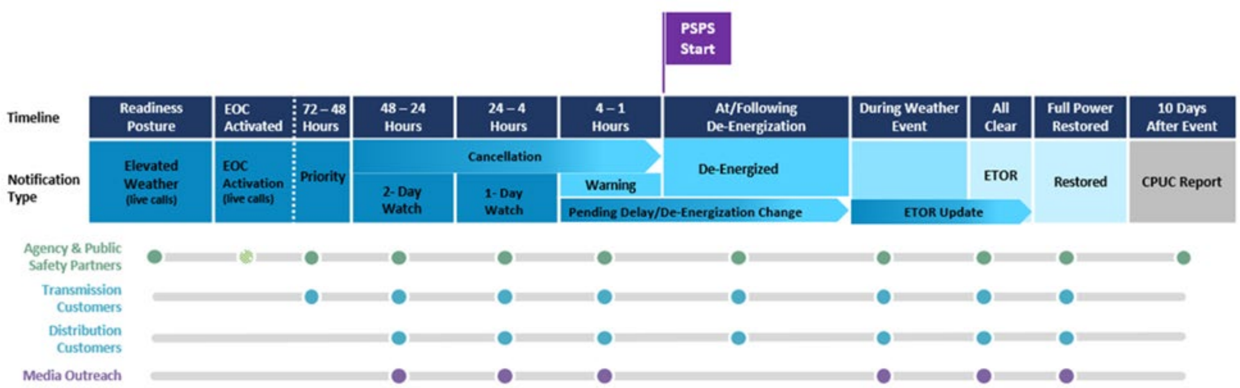
PG&E's communication strategy for wildfires is dependent on the severity of the wildfire and may involve the activation of the EOC (see Section 11.2.1). For further information on PG&E's communication strategy for wildfires, please see CERP, Wildfire Annex.

PG&E communicates with Public Safety Partners regarding assets in wildfire impacted areas, outages due to wildfire, and PSPS outages and service restoration. The PSS team engages external public safety partners (law enforcement, fire agencies and local county offices of emergency services) on an on-going basis to provide wildfire and PSPS emergency preparedness information and response support. In this capacity, the PSS members will serve as an "agency representative" with the respective public safety partner(s).

Communication Strategy for PSPS

PG&E's communication strategy for PSPS is outlined in Figure PG&E-11.3.1-1 below. For further information please see CERP PSPS Annex.[216]

FIGURE PG&E-11.3.1-1:
PSPS COMMUNICATION STRATEGY



Primarily, the PSS team will support direct contact with the county OES lead in the context of a PSPS event and will follow the communication protocols as outlined in our document posted to our PG&E website called "Your Guide to PSPS."[217] These

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[216] See PSPS Annex, Version 9.0 (July 31, 2024), Section 7, Customer and Agency Notifications and Resources, p. 7-1.

[217] The supporting document is available at: PG&E's Community Wildfire Safety Program.

protocols consist of one-on-one meetings, participation in “systemwide cooperator calls,” and establishing a presence in an external EOC if requested by an external entity.

Below is a high-level overview of PG&E’s communication efforts with Public Safety Partners during these events.

- Sending automated notifications to public safety partners at key milestones throughout the event so they can begin implementing their emergency response plans, ahead of customer notifications and know when service restoration is anticipated.

- Conducting ongoing coordination with local County OES and tribal contacts through dedicated Agency Representatives, following the protocols outlined in PG&E’s “Your Guide to PSPS.” These Agency Representatives are directly connected to our EOC and coordinate internally to gather critical, timely, and location-specific information when requested.

- Allowing Public Safety Partners to be embedded into our EOC, per CPUC requirements, and joining agencies in their local EOCs.

- Providing event-specific maps and reports via a secure data portal, as appropriate.

PG&E follows communications policies and procedures outlined in the documents listed below:[218]

- PSPS Policy & Procedures Guide for Emergency Managers;

- CERP;

- PSPS Annex;[219]

- Wildfire Annex; and

- Electric Annex.

Pursuant to Pub. Util. Code 768.6(b)(1)(c) and in compliance with Standard 14 of GO 166, PG&E provides local government stakeholders an opportunity to provide input into our emergency and disaster preparedness plans. In addition, when in wildfire emergency posture or in-scope for a PSPS event, our PSS team follows California’s SEMS as required by GO 166 and Pub. Util. Code Section 768.

See Table 11-3 below for a partial list of High Level Communication Protocols, Procedures, and Systems with Public Safety Partners. A complete list is available in Appendix F.

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[218] The supporting documents are available at: PG&E’s Community Wildfire Safety Program.

[219] PSPS Annex, Version 9.0 (July 31, 2024), Section 7, Customer and Agency Notifications and Resources, p. 7-1.

TABLE 11-3:
HIGH LEVEL COMMUNICATION PROTOCOLS, PROCEDURES, AND SYSTEMS WITH PUBLIC SAFETY PARTNERS

Public Safety Partner Group	Name of Entity	Key Protocols	Frequency of Pre-Arranged Communication Review and Update
City	City of Amador	See 11.3.1 narrative for key protocols.	Annually
City	City of American Canyon	See 11.3.1 narrative for key protocols.	Annually
City	City of Anderson	See 11.3.1 narrative for key protocols.	Annually
City	City of Angels Camp	See 11.3.1 narrative for key protocols.	Annually
City	City of Arcata	See 11.3.1 narrative for key protocols.	Annually

We have not encountered any gaps and limitations when collaborating with Public Safety Partners as shown in Table 11-4 below.

TABLE 11-4:
KEY GAPS AND LIMITATIONS IN COMMUNICATION COORDINATION WITH PUBLIC SAFETY PARTNERS

Gap or Limitation Subject	Brief Description of Gap or Limitation	Remedial Action Plan
N/A	N/A	N/A

11.3.2 Collaboration on Local and Regional Wildfire Mitigation Planning

In this section, the electrical corporation must provide a high-level overview of its plans, activities (programs), and/or policies for collaborating with communities on local and regional wildfire mitigation planning (e.g., wildfire safety elements in general plans, Community Wildfire Protection Plans (CWPP), local multi-hazard mitigation plans) within its service territory.[220] *The narrative must be no more than one page.*

In addition, the electrical corporation must provide the following information in tabular form, providing no more than one page of tabulated information in the main body of the WMP and the full table in an appendix as needed:

- *List of county, city, regional entities/task forces, and non-governmental organizations (e.g., nonprofits, fire safe councils) within the service territory with which the electrical corporation has collaborated or intends to collaborate on local wildfire mitigation planning efforts (i.e., non-wildfire emergency planning activities):*

[220] *Pub. Util. Code § 8386(c)(19).*

- *For each entity, the local or regional wildfire mitigation planning program/plan/document, level of collaboration (e.g., meeting attendance, verbal or written comments, data sharing, risk assessment), and date the electrical corporation provided its last feedback.*
- *In a separate table, the electrical corporation must provide a list of current gaps and limitations in its collaboration efforts with local and regional partners on local wildfire planning efforts. Where gaps or limitations exist, the electrical corporation must indicate proposed means and methods to increase collaborative efforts.*

See Table 11-5 for a partial list of Collaboration in local and Regional Wildfire Mitigation Planning below. A complete list is available in Appendix F.

TABLE 11-5:
COLLABORATION IN LOCAL AND REGIONAL WILDFIRE MITIGATION PLANNING

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., Non-Governmental Organization, Fire Safe Council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
Redwood City San Carlos Fire Department	Redwood San Carlos Fire Assembly Bill (AB) 56	1/3/2023	Met with Battalion Chief Lax
San Mateo Consolidated Fire	San Mateo Consolidated AB 56	1/4/2023	Met with Battalion Chief Tony Blackman at EOC.
San Mateo County Department of Emergency Management	San Mateo Consolidated AB 56	1/4/2023	Met with Battalion Chief Tony Blackman at EOC.
Orland Fire Protection District	Glenn County Fire Chiefs Meeting	1/11/2023	Monthly meeting held at Glenn-Codora Fire. Discussed AB 56 gas compliance and each agency chief received gas complaisance folder.
Capay Fire Protection District	Glenn County Fire Chiefs Meeting	1/11/2023	Monthly meeting held at Glenn-Codora Fire. Discussed AB 56 gas compliance and each agency chief received gas complaisance folder.

Table 11-6 below summarizes key gaps and limitations in collaborating on local and regional wildfire mitigation planning.

TABLE 11-6:
KEY GAPS AND LIMITATIONS IN COLLABORATING ON LOCAL AND REGIONAL WILDFIRE MITIGATION PLANNING

Subject of Gap or Limitation	Brief Description of Gap or Limitation	Strategy for Improvement
PG&E roles and responsibilities	PG&E is not the lead authority for wildfires, nor can we require local jurisdictions to create wildfire plans.	Strategy: PG&E remains committed to helping our partners. PG&E will continue to review and provide feedback on local wildfire plans, as it relates to electric and gas impacts during a wildfire, if requested by the local jurisdiction. Target Timeline: Ongoing.
Collaboration with local wildfire mitigation planning	Our wildfire & climate resiliency work is not connected to the work of communities & agencies	Strategy: Wildfire & Climate Resiliency Chief is currently developing a Wildfire Resilience Corridors pilot with a community within our Areas of Concern (AOC). The pilot's goal is to co-develop wildfire mitigation programs and projects with pilot communities that will mutually benefit both community assets and utility infrastructure. Planned projects may be jointly funded with the pilot community. Target Timeline: 2025-2028.

PG&E has launched a pilot Wildfire Resilience Corridors to increase our existing collaboration with local wildfire mitigation planning efforts. The pilot will start with communities within our AOC, high-risk locations primarily in the HFRA, that are undertaking a CWPP update process. The pilot will leverage both our Regional Service Model and our system-wide risk modeling to provide more targeted wildfire mitigation strategies to these communities. The pilot components will include: engagement with CWPP risk assessments; work-plan coordination; and project co-development (Wildfire Resilience Corridors). The identified Wildfire Resilience Corridors will be voluntary fuels reduction projects where CWPP priority treatment areas intersect with our AOC. This pilot program will be evaluated and refined to focus limited resources on the most effective community risk reduction projects and to deepen local relationships within our Regional Service Model. This pilot will be managed by the Wildfire & Climate Resiliency Chief.

In addition to these local pilots, PG&E is an active participant in the Governor’s Wildfire & Forest Resilience Task Force meetings and working groups, including the Fire Adapted Communities working group and Interagency Treatment Tracker mapping effort. We are also contributing to the development of the Task Force’s 2025 Action Plan update, which will be implemented during the 2026-2028 period.

11.3.3 Collaboration With Tribal Governments

In this section, the electrical corporation must provide a high-level overview of its plans, activities (programs) and/or policies for collaborating on local wildfire mitigation planning with tribal governments served by the electrical corporation and on whose lands its infrastructure is located.[221] *The narrative must be no more than one page.*

In addition, the electrical corporation must provide the following information in tabular form, with no more than one page of tabulated information in the main body of the WMP and the full table in an appendix as needed:

- List of tribal governments served by the electrical corporation and on whose lands its infrastructure is located with which the electrical corporation has collaborated or intends to collaborate on local wildfire mitigation planning efforts (i.e., non-wildfire emergency planning activities):
  - *For each entity, the local wildfire mitigation planning program/plan/document, level of collaboration (e.g., meeting attendance, verbal or written comments), and date the electrical corporation provided its last feedback.*
  - *In a separate table, the electrical corporation must provide a list of current gaps and limitations in its collaboration efforts with local partners on local wildfire planning efforts. Where gaps or limitations exist, the electrical corporation must indicate proposed means and methods to increase collaborative efforts.*

At a high level, PG&E collaborates with tribal agencies on mitigation planning as described below.

- PG&E conducts tribal outreach for wildfire mitigation throughout the year. The outreach to tribal governments includes several meetings, e-mails, and training opportunities. Outreach includes all tribes within the PG&E service area.
- Tribal Contact List Outreach: Direct outreach to tribes to receive updated contact information.
- Internal Tribal Competency Training: Internal training to facilitate an understanding of how tribal governments function.
- Programs Available to Tribes: Notify tribes of programs available to assist them with mitigation of wildfire related outages.
- Community Wildfire Safety Webinar: Inform stakeholders, including Tribes, about PG&E's Community Wildfire Safety Program (CWSP) and any new developments it might have.

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[221] *Pub. Util. Code § 8386(c)(19).*

- Regional Town Hall CWSP: Work with regional stakeholders via town hall meeting to review and improve CWSP processes.

- Tribal Grant Program Review: Work with tribes to participate in Federal and California state grants.

- Tribal Newsletter to all Tribes: Create and share a quarterly Tribal Newsletter with relevant PG&E updates.

- Critical Facilities Outreach and Review: Work with Critical Facilities, including tribal facilities, to ensure processes and availability are up to date.

- Undergrounding Plan: Outreach to avoid sensitive areas and collaborate on tribal preservation practices.

- Vegetation Management: Avoidance of sensitive areas and attention to tribal needs around electric lines on tribal lands.

- PSPS Outreach: PG&E follows the required notification process for PSPS events. This includes before, during, and after a PSPS event. Outreach is conducted through e-mail and calls prior to each PSPS beginning with the notification of the EOC opening. A cadence of calls and e-mails follows throughout the PSPS event including twice a day updates, a daily Tribal Cooperators call and finally an all-restored e-mail notification when the power has been restored. Throughout a PSPS event, tribes are made aware of resources to assist them and programs that are available to them to mitigate the loss of power in their community.

See Table 11-7 for a part list of Collaboration with Tribal Agencies below. A complete list is available in Appendix F.

TABLE 11-7:
COLLABORATION WITH TRIBAL AGENCIES

Name of County, City, or Tribal Agency or Civil Society Organization (e.g., nongovernmental organization, fire safe council)	Program, Plan, or Document	Last Version of Collaboration	Level of Collaboration
WASHOE TRIBE	See Section 11.3.3: Collaboration with Tribal Governments	2024 quarterly meetings, e-mails, calls, newsletter, in person meeting if requested	Communications sent to tribal governments
JACKSON RANCHERIA	See Section 11.3.3: Collaboration with Tribal Governments	2024 quarterly meetings, e-mails, calls, newsletter, in person meeting if requested	Communications sent to tribal governments
IONE BAND OF MIWOK INDIANS	See Section 11.3.3: Collaboration with Tribal Governments	2024 quarterly meetings, e-mails, calls, newsletter, in person meeting if requested	Communications sent to tribal governments
BUENA VISTA RANCHERIA	See Section 11.3.3: Collaboration with Tribal Governments	2024 quarterly meetings, e-mails, calls, newsletter, in person meeting if requested	Communications sent to tribal governments
BERRY CREEK RANCHERIA	See Section 11.3.3: Collaboration with Tribal Governments	2024 quarterly meetings, e-mails, calls, newsletter, in person meeting if requested	Communications sent to tribal governments

Table 11-8 below summarizes key gaps and limitations in collaborating with tribal agencies.

TABLE 11-8:
KEY GAPS AND LIMITATIONS IN COLLABORATING WITH TRIBAL AGENCIES

Subject of Gap or Limitation	Brief Description of Gap or Limitation	Strategy for Improvement
Staffing	The tribal team is limited to two Full-Time Equivalents to cover the entire service area. Additional team members are needed to cover the 112 tribal governments in the service area.	The team is working on hiring of additional support for a regional tribal outreach and engagement model. Working to bring individuals on to assist in 2025.

11.4 Public Communication, Outreach, and Education Awareness

The electrical corporation must describe at a high level its comprehensive communication strategy to inform essential customers and other stakeholder groups of wildfires, outages due to wildfires, and PSPS and service restoration, as required by Pub. Util. Code Section 768.6.[222] *This should include a discussion of the policies, practices, and procedures the electrical corporation adopts to establish appropriate communication protocols to ensure timely, accurate, and complete communications. The electrical corporation may refer to its Pub. Util. Code Section 768.6 emergency preparedness plan to provide more detail. The narrative must be no more than one page.*

In the following sections, the electrical corporation must provide an overview of the following components of an effective and comprehensive communication strategy:

- *Protocols for emergency communications;*
- *Messaging;*
- *Outreach and education awareness program(s) for wildfires, PSPS events, and Protective Equipment and Device Settings; service restoration before, during, and after incidents; and Vegetation Management (VM); and*
- *Current gaps and limitations.*

The electrical corporation must reference the Tracking ID where appropriate.

Tracking IDs: CO-04, CO-05

Public communication, outreach, and education awareness are key components of emergency planning and preparedness. These efforts help to ensure customers and communities are informed and adequately prepared prior to a wildfire or wildfire safety outage like PSPS or EPSS. PG&E leverages the Safety Partner, Community-Based Organizations (CBO), and customer engagement opportunities described in Section 11.4.4 to gather feedback on the engagement plans for PSPS and EPSS outages.

PG&E hosts safety-focused community engagement events, including regional town halls and community webinars to engage directly with customers. We use these events to convey local wildfire safety information in advance of wildfire season and discuss the impacts that wildfire safety efforts have on the community. In addition, we complete annual PSPS education and outreach engagement surveys to collect input/feedback from our customers.

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222 *Pub. Util. Code § 8386(c)(7), (19).*

Community Engagement – Outreach to HFRA Infrastructure Customers: PG&E will perform annual outreach via e-mail and/or phone to assigned Critical Infrastructure customers in the HFRA through Business Energy Solutions (assigned account managers). Outreach will cover the WMP, including potential PSPS and EPSS impacts, and updating contact information for critical accounts in the HFRA. See CO-04 in Table 11-1 in Section 11.1.1 for more information.

Community Engagement – Outage Preparedness Campaign: PG&E will conduct at least one direct-to-customer outage preparedness campaign annually via e-mail and/or direct mail targeting residential customers within the PSPS and EPSS Program scope. See CO-05 in Table 11-1 in Section 11.1.1 for more information.

11.4.1 Protocols for Emergency Communications

The electrical corporation must identify the relevant stakeholder groups and target communities in its service territory and describe the protocols, practices, and procedures used to provide notification of wildfires, outages due to wildfires and PSPS, and service restoration before, during, and after each incident type.[223] *Stakeholder groups and target communities include, but are not limited to: the general public; priority essential services;*[224] *AFN populations and other vulnerable or marginalized populations; populations with limited English proficiency; Tribal Nations; and people in remote areas. The narrative must include a brief discussion of the decision-making process and use of best practices to ensure timely, accurate, and complete communications. The narrative must be no more than one page.*

In addition, the electrical corporation must summarize the interests or concerns each stakeholder group/target community may have before, during, or after a wildfire or PSPS event to help inform outreach and education awareness needs. Table 11-9 provides the required format for this summary.

For protocols for emergency communication please see Section 11.4.1 and the CERP Emergency Communications Annex[225] and PSPS Annex.[226]

PG&E conducts extensive outreach to stakeholders following activation of the PG&E EOC. Key stakeholders include: (1) City, County, State, and Federal Agencies; (2) tribal governments; (3) First Responders; (4) Medical Baseline (MBL) Program and Self-Identified Vulnerable (SIV) Customers; (5) Limited English Proficiency (6) CBO in-event support and resources; (7) Critical Facilities and Infrastructure (CFI);

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223 *Pub. Util. Code § 8386(c)(7).*

224 *Priority essential services include, but are not limited to: public safety offices, critical first responders, health care facilities and operators, and telecommunications infrastructure and operators.*

225 PG&E Emergency Communications Annex to the CERP, Version 8 (June 4, 2024).

226 PSPS Annex, Version 9.0 (July 31, 2024), Section 7, Customer and Agency Notifications and Resources, p. 7-1.

(8) telecommunications and water providers; (9) transmission-level entities; (10) third-party commodity suppliers; (11) media; and (12) the general public.

When PG&E's EOC activates for a potential PSPS event, it notifies the CPUC and Cal OES that the EOC is activated and sends additional notices at key milestones throughout the process. In addition to automated notifications, PG&E conducts supplemental outreach and verification of message receipt to each stakeholder group. This outreach is frequent, tailored to the stakeholder's needs, and focuses on providing the latest event information.

Our dedicated CBO team maintains communications with CBOs and resource partners before, during, and after PSPS, wildfires, and other emergencies. During a PSPS, PG&E invites all CBOs to participate in the daily Systemwide Cooperators Call hosted by EOC staff to share PSPS updates. CBOs are provided courtesy e-mail notifications throughout the event with updates and access to a dedicated e-mail. CBO resource partners are also sent PSPS priority/advance notifications to prepare resources for deployment. PG&E's dedicated EOC team hosts a CBO Resource Partner coordination call, which allows resource CBOs supporting the PSPS event or other emergency, to ask questions and share best practices.

During a PSPS, vulnerable customer groups whose health and safety are at risk with loss of power, including MBL and SIV customers, require additional attention and action to ensure their notifications have been received. In some cases, PG&E may also make Live Agent phone calls along with the automated notifications and doorbell rings as an additional attempt to reach the customer prior to and/or after de-energization.[227]

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[227] SIV is inclusive of customers who have indicated they are "dependent on electricity for durable medical equipment or assistive technology," as well as customers that are not enrolled or qualify for the MBL Program and "certify that they have a serious illness or condition that could become life threatening if service is disconnected." In accordance with D.21-06-034, PG&E includes customers who have indicated they are "dependent on electricity for durable medical equipment or assistive technology" to identify customers "above and beyond those in the MBL population" to include persons reliant on electricity to maintain necessary life functions including for durable medical equipment and assistive technology. This designation remains on their account indefinitely.

See Table 11-9 for a partial list of protocols for emergency communication to stakeholder groups below. A complete list is available in Appendix F.

TABLE 11-9:
PROTOCOLS FOR EMERGENCY COMMUNICATION TO STAKEHOLDER GROUPS

Stakeholder Group/Target Community	Event Type	Method(s) for Communicating	Means to Verify Message Receipt	Interests or Concerns Before, During, and After Wildfire and PSPS Events
City, County, State, and Federal Agencies	Wildfire	None	None	Electric service outage information
City, County, State, and Federal Agencies	Wildfire-related outage	Phone Call/Text/E-mail regarding status of electric service	None	Electric service outage information
City, County, State, and Federal Agencies	PSPS-related outage	Phone/Text/E-mail notifications, with re-attempts	Automated notification tracking	PSPS Outage Start time, Portal updates, estimated time of restoration, AFN support resources, Community Resource Center (CRC) locations,
City, County, State, and Federal Agencies	Restoration of service	Phone/Text/E mail notifications	Automated notification tracking	Estimated time of restoration
Tribal Governments	Wildfire	E-mail to tribally-identified/ approved contacts from Tribal Liaison. Outreach or PSS as needed	Request message receipts	PG&E supports efforts to protect the health and safety of residents on tribal lands during wildfires. Throughout the year we work with tribal governments to plan infrastructure maintenance on tribal lands and provide quarterly wildfire safety webinars through our Regional Workgroups. We provide support as requested during wildfire suppression activities through our PSS and SIPT teams.

11.4.2 Messaging

In this section, the electrical corporation must describe its procedures for developing effective messaging to reach the largest percentage of stakeholders in its service territory before, during, and after a wildfire, an outage due to wildfire, or a PSPS event.[228]

In addition, the electrical corporation must provide an overview of the development of the following aspects of its communication messaging strategy:

- *Features to maximize accessibility of the messaging (e.g., font size, color contrast analyzer);*
- *Alert and notification schedules;*
- *Translation of notifications;*
- *Messaging tone and language; and*
- *Key components and order of messaging content (e.g., hazard, location, time).*

The narrative must be no more than one page.

PG&E communicates to help customers prepare for the possibility of a PSPS and or wildfire event (see Section 11.4.3.) PG&E sends notifications prior to a PSPS event (see Section 11.4.1, Table 11-9 Protocols for Emergency Communication to Stakeholder Groups for a detailed overview of notification protocols by stakeholder customer groups).

Features to Maximize Accessibility of Messaging

PG&E uses its best efforts to include key information in large print in all standard printed materials about wildfire or PSPS preparedness and PSPS events. Ongoing processes and validations are taking place to ensure that customers who receive their bills in alternative formats such as Braille and large print, also receive all their messaging materials in the same format. PG&E's online customer communications, including pge.com and PSPS customer notification e-mails, meet Web Content Accessibility Guidelines (WCAG) 2.0 AA Standards for accessibility. Since 2022, new content has been tested to meet WCAG 2.1 AA Standards.

Alert and Notification Schedules – PSPS Customer Notifications

Pursuant to the CPUC's PSPS Phase 1 Decision (D).19-05-042, PG&E schedules PSPS notifications for potentially impacted customers two days, one day, and just prior to power shutoff. Customers are notified upon power restoration. Priority notifications are made to Public Safety Partners 72-48 hours in advance of de-energization.

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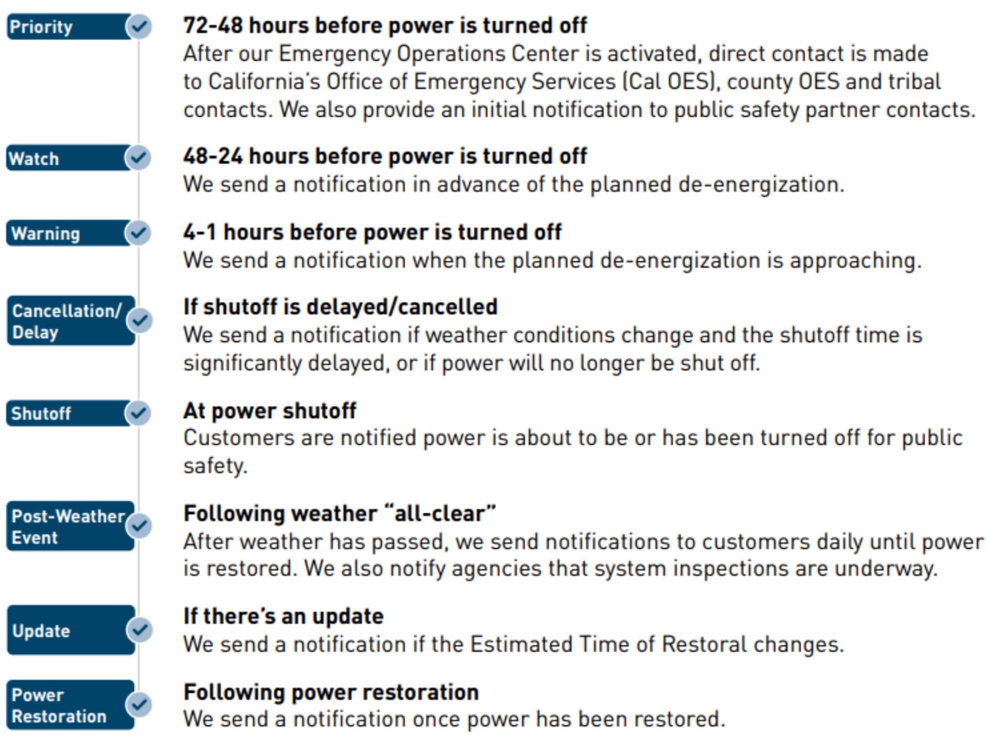
[228] *Pub. Util. Code § 8386(c)(7), (19).*

Notifications include any potentially impacted locations, forecasted date and time of power shutoff, estimated restoration date and time, and links to maps and event-specific information.

PG&E provides the most current information about its emergency response efforts, rebuilding and recovery, available customer resources, and protection protocols using mediums such as news releases, media interviews, and social media posts. PSPS information is available on pge.com/pspsupdates. PG&E maximizes accessibility to this critical information by translating its website and other critical wildfire safety and PSPS preparedness materials into 15 non-English languages.

Figure PG&E-11.4.2-1 below represents the types of PSPS notifications.

FIGURE PG&E-11.4.2-1:
PSPS NOTIFICATIONS



Translation of Notifications – Limited English Proficiency

Outbound notifications are available in 16 languages provided the customer has indicated a language preference. PG&E conducts extensive testing, including dial-test focus groups, to understand ways to best communicate across demographics. PG&E's Contact Center provides translation support in over 240 languages.

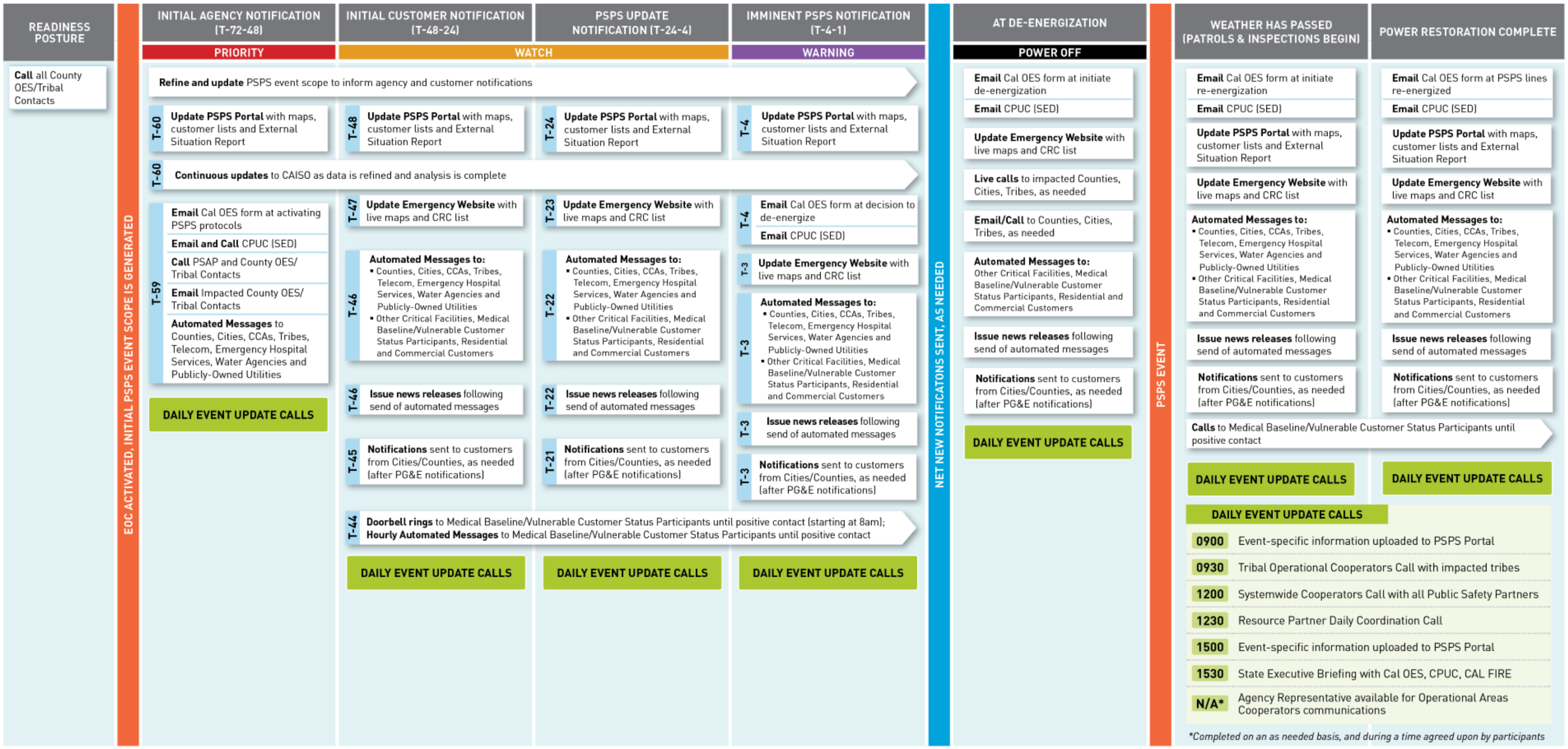
Messaging Tone and Language

Pursuant to the CPUC's PSPS Phase 2 D.20-05-051 and PG&E's brand and digital guidelines, all notifications to customers regarding potential or active PSPS events and outages due to wildfires are communicated with ease of readability and comprehension. PG&E's accessibility requirements aim for customer communication to be written at or below the Grade 9.0 reading level to help customers with cognitive disabilities understand more easily. Furthermore, PG&E communications are provided in the language preferred by the customer. Whenever reasonably possible, PG&E communications are made available for people with disabilities who may not be able to use standard forms of communication.

Key components and order of messaging content (e.g., hazard, location, time)

Figure PG&E-11.4.2-2 below provides an overview of PSPS notifications, including PSPS restoration notifications. During outages due to wildfires, PG&E follows the established emergency communication framework outlined in the CERP and GO 166 standards (see Section 11.4.2, Outage Reporting).

FIGURE PG&E-11.4.2-2:
PSPS NOTIFICATIONS



ACRONYMS: EOC: Emergency Operations Center | **OES:** Office of Emergency Services | **PSAP:** Public Safety Answering Points | **CCA:** Community Choice Aggregator | **CPUC:** California Public Utilities Commission

11.4.3 Outreach and Education Awareness Activities

In tabulated format, the electrical corporation must provide a list the various outreach and education awareness activities (programs) (i.e., campaigns, informal education, grant programs, participatory learning) that the electrical corporation implements before, during, and after wildfire, vegetation management, and PSPS events to target communities, including efforts to engage with partners in developing and exercising these activities (programs).[229] *In addition, the electrical corporation must describe how it implements its overall program, including staff and volunteer needs, other resource needs, method for implementation (e.g., industry best practice, latest research in methods for risk communication, social marketing), long-term monitoring and evaluation of each program's success, need for improvement, etc. The narrative for this section is limited to two to three pages.*

Prior to peak wildfire season, PG&E designs and executes a comprehensive wildfire safety and PSPS preparedness community outreach strategy. PG&E conducts community outreach to educate agencies, customers, and property owners on aspects of our wildfire mitigation practices, such as EPSS, community resilience, and system hardening, and the role they play in helping to reduce wildfire risks in their communities.

Key community groups include: AFN customers;[230] residential and unassigned Small and Medium Business (SMB) customers; property owners and property managers; critical facility providers, such as water agencies, communications providers, and hospitals; and CBOs. PG&E incorporates multiple channels and tactics into its engagement approach that enable PG&E to hear and act upon feedback from agencies,[231] CBOs, other community stakeholders, agencies, and communities impacted in prior fire seasons.

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[229] *Pub. Util. Code § 8386(c)(19).*

[230] The term "access and functional needs populations" refers to those populations with AFN as set forth in Government Code § 8593.3. Government Code § 8593.3(f)(1) lists access and functional needs populations as follows: "[a]ccess and functional needs population' consists of individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, older adults, children, people living in institutionalized settings, or those who are low income, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or those who are pregnant."

[231] See WMP Initiative CO-04 Community Engagement – Outreach to HFRA Infrastructure Customers, which uses a multi-channel approach to perform outreach via e-mail and/or phone to assigned Critical Infrastructure customers in the HFRA through Business Energy Solutions (assigned account managers). Outreach will cover the CWSP, including potential PSPS and EPSS impacts, and updating contact information for critical accounts in the HFRA.

The following PG&E employees support community outreach efforts:

- One PSPS Customer Outreach Strategist and a Customer Care Program Marketing Manager conduct annual education and outreach to all customers in HFRA, including AFN.
- One Program Manager and one Program Specialist who work with over 500 CBO's supporting or sharing messaging with AFN customers.
- Eighteen employees support unassigned SMB customers.
- One Program Manager and 85 assigned account managers to support critical facility providers, such as water agencies, communications providers, and hospitals.

PG&E monitors and evaluates the long-term success of its programs and needed improvement drivers as follows:

- <u>AFN</u>: PG&E uses its Pre- and Post-Season survey results as a Key Performance Indicator to measure its effectiveness for AFN customers in the areas of preparedness and program resource awareness. Furthermore, PG&E conducts PSPS post-event surveys to impacted customers, including AFN, to obtain in-event feedback to help PG&E address improvement needs. As a member of the California Joint IOUs AFN team, key metrics are reviewed related to outreach and awareness. The team collaboratively aligns strategies to help drive growth in all areas.
- <u>CBO</u>: PG&E conducts recurring outreach with its CBOs and continuously solicits feedback on improvements required to support each CBO in supporting PG&E AFN customers. PG&E conducts PSPS post-event surveys for CBOs to obtain in-event feedback and help PG&E address CBO needs. Identified improvements are discussed quarterly in PG&E's AFN Quarterly Progress Reports.
- <u>SMB and CFI</u>: With the support of account managers, PG&E conducts annual reviews of locations within the HFRA with Critical Facilities and other assigned accounts, including Telecommunications partners. During Emergency activations, including PSPS, these customers have direct lines of communication with the customer strategy team for immediate feedback and informational updates.

While PG&E's engagement for the PSPS program continues to mature and will remain an area of focus, other key wildfire mitigations are driving additional needs for engagement, including EPSS and Undergrounding. PG&E will focus on further integrating awareness and education about EPSS into broader CWSP customer messaging about wildfire safety outages. Direct-to-customer mail, e-mail, and other outreach materials provide overall awareness of the CWSP and operational mitigations such as PSPS and EPSS.

PG&E monitors customers and communities impacted by multiple outages on EPSS-enabled circuits. PG&E may leverage automated outage notifications, follow-up Interactive Voice Recording messages, customer e-mails, e-mails to elected officials, social media posts, community webinars, and in-person community meetings, as appropriate, to communicate with highly impacted customers to explain outages and actions PG&E is taking to reduce future impacts. As the peak wildfire season passes, PG&E communicates with customers served by EPSS-enabled circuits to summarize the program's benefits for the year and acknowledge program successes and opportunities for improvement. PG&E coordinates with CFI—such as hospitals, telecommunication providers, and transportation agencies, among others—to further understand and more effectively plan for the impacts of wildfire and PSPS events, with a focus on how to safely operate these facilities during a wildfire or outage event.

Engagement with CFIs is conducted annually to validate contact information and coordinate resiliency planning efforts associated with backup generation. In addition, PG&E sends an annual communication reminding CFIs that PG&E does not provide backup power before or during PSPS and wildfire events. PG&E provides critical facilities, including transmission-level customers, with advanced notifications, prioritized restoration, and additional communications and other resources before and during outages. In alignment with other IOUs, CFIs can request a backup power assessment, and PG&E provides them with online resources, tools, and preparedness information related to their business needs.

One of PG&E's highest priorities during wildfire related emergencies, including PSPS, is to protect the health and safety of our vulnerable/AFN customers and communities. PG&E conducts outreach related to emergency preparedness, provides an improved notification experience before and during PSPS events, and offers additional services and resources to these customers in advance of and during PSPS events and wildfires. Outreach to vulnerable/AFN customers and communities is conducted in accordance with the *Enhanced Customer and Community Support During All Hazards Standard (*EMER7001S-),[232] either directly or in partnership with CBOs.

PG&E plans to continue partnerships with CBOs to increase wildfire safety outreach and education to support vulnerable/AFN customers. More specifically, PG&E is focused on customers with identified language preference and customers who have an individual in the household who self identifies as vulnerable (e.g., self-certified vulnerable, self-identified reliant on power for durable medical equipment or assistive technology) and/or identifies as AFN. PG&E's 2025 PSPS AFN Plan,[233] filed January 31, 2025, provides more details on PG&E's goals, strategies, and tactics to support AFN customers and communities before, during, and after PSPS events.

CBO Resource Partners have agreed to receive information and assist with outreach to the people they work with before, during and after wildfire season to assist with preparations for wildfire safety outages such as PSPS or EPSS. Informational CBOs have agreed to receive information from PG&E and will share as appropriate with the people they work with.

PG&E executes a multi-touch Emergency Preparedness Safety Awareness campaign to provide education to customers, non-account holders, visitors, and communities throughout our service territory—before, during, and after events. This campaign helps

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232 The supporting document is available at: PG&E's Community Wildfire Safety Program.

233 See R.18-12-005, PG&E's 2025 AFN Plan for PSPS Support (Jan. 31, 2025). The supporting document is available at: PG&E's Community Wildfire Safety Program.

them prepare for emergency situations by updating contact information to ensure delivery of PG&E notifications, signing up for the MBL Program, and/or self-certifying for Vulnerable Customer status or self-identifying as AFN. PG&E takes a collaborative approach to our public awareness initiatives by partnering with local public safety officials and community stakeholders to expand the reach of our activities. PG&E uses the tactics described in Table 11-11 below to increase public awareness about emergency preparedness.

PG&E seeks input from the other IOUs and advisory committees to apply best practices and identify additional community groups to include in public outreach and awareness efforts. Table 11-10 below lists the communities PG&E engages with around wildfire safety and PSPS preparedness through our comprehensive community outreach strategy.

TABLE 11-10:
LIST OF TARGET COMMUNITIES

Target Community	Interests or Concerns Before, During, and After Wildfire and PSPS Events
MBL Allowance Program Participants (including individuals reliant on Life Support)	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information to receive notifications and the importance of notification acknowledgement to confirm receipt. Continuous power, including portable battery options and backup generation rebates for qualified customers, and overall resilience support available.
SIV or reliant on electricity for durable medical equipment or assistive technology	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information to receive notifications and the importance of notification acknowledgement to confirm receipt. Continuous power, including portable battery options and backup generation rebates for qualified customers, and overall resilience support available.
Income-Qualified	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information to receive notifications. Available backup generation rebates for qualified customers, food replacement options, MBL Allowance Program and overall resilience support available.
Limited English Proficiency	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information and indicate language preference to receive notifications in preferred language. Available backup generation rebates for qualified customers and overall resilience support available. Education materials available in preferred language
Blind or Low Vision	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information to receive notifications. Available backup generation rebates for qualified customers and overall resilience support available. Education materials available in large print or Braille.

TABLE 11-10:
PG&E'S LIST OF TARGET COMMUNITIES
(CONTINUED)

Target Community	Interests or Concerns Before, During, and After Wildfire and PSPS Events
Deaf or Hard of Hearing	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information to receive notifications. Available backup generation rebates for qualified customers and overall resilience support available. Education materials are available in American Sign Language (ASL).
Disabled (Physical, Cognitive or Developmental) or Age 65+	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information to receive notifications. Available backup generation rebates for qualified customers, food replacement options, MBL Allowance Program and overall resilience support available.
Residential and SMB Unassigned Customers of Record	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information to receive notifications. Available backup generation rebates for qualified customers.
Property Owners and Property Managers	How to educate tenants to drive awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to sign up for Address Level Alerts to receive direct notification of possible PSPS for non-account holders and promotion of the MBL Program. Available backup generation rebates for qualified customers.
Critical Facilities	Awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information to receive notifications. Available backup generation resources and coordination of resilience plan with the utility.
CBO	How to educate consumers to drive awareness of and preparation for potential PSPS, wildfire or unplanned outages where EPSS is enabled, including how to update contact information (account holders) or sign up for Address Level Alerts to receive direct notification of possible PSPS (non-account holders) and promotion of applicable programs such as the MBL Program, continuous power options, including portable battery options and backup generation rebates, and overall resilience support available.
Vegetation Management	For the systemwide Annual Maintenance and Second Patrol programs, PG&E sends notifications to customers via e-mail ~3-7 days in advance of both inspection and tree work. For the Vegetation Control program (clearing around the base of poles), PG&E sends notifications to customers via e-mail ~3-7 days in advance of performing work. For this program, inspection and tree work are typically performed on the same day. For the Integrated Vegetation Management program (transmission), PG&E sends direct mail to landowners notifying them of vegetation work along our transmission corridor. In 2025, PG&E will also begin sending e-mail notifications to customers ahead of this work. For select vegetation projects in sensitive areas (e.g., previous wildfire, old growth trees), PG&E may send a tailored notification to customers via direct mail or e-mail. Additionally, PG&E may host a community open house to describe our work and answer questions in person.

Table PG&E-11.4.3-1 below summarizes our public communication, outreach, and education awareness programs.

TABLE PG&E-11.4.3-1:
PG&E'S PUBLIC COMMUNICATION, OUTREACH, AND EDUCATION AWARENESS PROGRAMS

Core Activity	Event Type	Period of Application (Before, During, After Incident)	Name of Outreach or Education Program	Description of Program	Target Audience	Reference/ Link
Awareness and Preparedness Education	PSPS, Wildfire Safety, EPSS	Before, During, After Incident	CWSP	Virtual education about PSPS, wildfire safety, EPSS, etc. To educate all customers to be prepared.	Customers	www.pge.com/firesafetywebinars
Awareness and Preparedness Education	PSPS, Wildfire Safety, EPSS	Before, During, After Incident	CWSP	Virtual or in person education about PSPS, wildfire safety, EPSS, etc. To educate all customers to be prepared.	Customers	N/A
Awareness and Preparedness Education	PSPS, Wildfire Safety, EPSS	Before	CWSP	Virtual education about PSPS, wildfire safety, EPSS, etc. To educate partner agencies and organizations for message amplification.	In-Home Support Services, Regional Centers, California Foundation for Independent Living Centers (CFILC), and other CBO Informational Partners	www.pge.com/firesafetywebinars
Awareness and Preparedness Education	PSPS, Wildfire Safety, EPSS	Before	CWSP	Virtual education about PSPS, wildfire safety, EPSS, etc. To educate partner agencies and organizations for message amplification.	Multi-cultural media partners	N/A
Awareness and Preparedness Education	PSPS, EPSS, MBL	Before, during	CWSP	Radio, online and social media education about PSPS, EPSS, MBL, and other preparedness and resource information.	Customers, AFN, Master Meter, MBL, visitors, multi-cultural	N/A
Awareness and Preparedness Education	PSPS, Wildfire Safety, EPSS	Before	CWSP	E-mail outreach with awareness, preparedness and resources information about PSPS, wildfire safety, EPSS, contact information, etc.	Customers, AFN, Master Meter, MBL, CBOs	N/A
Awareness and Preparedness Education	PSPS, Wildfire Safety, EPSS	Before	CWSP	Direct mail outreach with awareness, preparedness and resources information about PSPS, wildfire safety, EPSS, contact information, etc.	Customers, AFN, MBL	N/A

TABLE PG&E-11.4.3-1:
PG&E'S PUBLIC COMMUNICATION, OUTREACH, AND EDUCATION AWARENESS PROGRAMS
(CONTINUED)

Core Activity	Event Type	Period of Application (Before, During, After Incident)	Name of Outreach or Education Program	Description of Program	Target Audience	Reference/ Link
Awareness and Preparedness Education	PSPS, Wildfire Safety, EPSS	Before	CWSP	Bill inserts with awareness, preparedness and resources information about PSPS, wildfire safety, EPSS, contact information, etc.	MBL	N/A
MBL Acquisition	MBL	Before	MBL	Acquisition outreach via paid media, social media, e-mail and direct mail for the MBL Program.	AFN/MBL	N/A
EPSS Multiple Outage Follow-Up	Wildfire Safety	After	CWSP	Acknowledgement of recent outages and actions PG&E is taking to improve reliability in the community.	Customers	N/A
EPSS Multiple Outage Follow-Up	Wildfire Safety	After	CWSP	Acknowledgement of recent outages and actions PG&E is taking to improve reliability in the community.	Elected Officials	N/A
EPSS Multiple Outage Follow-Up	Wildfire Safety	After	CWSP	Acknowledgement of recent outages and actions PG&E is taking to improve reliability in the community.	Customers	www.pge.com/firesafetywebinars
EPSS Multiple Outage Follow-Up	Wildfire Safety	After	CWSP	Acknowledgement of recent outages and actions PG&E is taking to improve reliability in the community.	Customers, Elected Officials	N/A

11.4.4 Engagement With AFN Populations

The electrical corporation must provide an overview of its process for understanding, evaluating, designing, and implementing wildfire and outage program risk initiative strategies, policies, and procedures specific to AFN customers across its territory.[234] *The electrical corporation must provide its AFN plan as an attachment and may it to provide more detail. The electrical corporation must also report on the following:*

- *Summary of key AFN demographics, distribution, and percentage of total customer base;*
- *Evaluation of the specific challenges and needs during a wildfire or PSPS event of the electrical corporation's AFN customer base; and*
- *Plans to address specific needs of the AFN customer base throughout the service territory specific to the unique threats that wildfires and PSPS events may pose for those populations before, during, and after the incidents. This should include high-level strategies, policies, programs, and procedures for outreach, engagement in the development and implementation of the AFN-specific risk initiative strategies, and ongoing feedback practices.*

The electrical corporation must reference the Tracking ID where appropriate.

Tracking ID: N/A

Summary of Key AFN Demographics

For a more complete overview of our engagement with AFN populations please review our 2025 AFN Plan,[235] which includes a summary of key AFN demographics, evaluation of the specific challenges and needs, and plans to address specific needs of AFN customers. Our plan is also updated on a quarterly basis and those updates can be found here: Quarterly AFN Plan Updates.

Key AFN Demographics, Distribution, and percent of Total Customer Base

See Table PG&E-11.4.4-1 Identifying AFN Customers for a summary of the AFN customer base by demographics and distribution as of January 31, 2025.

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[234] *Pub. Util. Code § 8386(c)(7), (19).*

[235] The supporting document is available at: PG&E's Community Wildfire Safety Program.

TABLE PG&E-11.4.4-1:
IDENTIFYING AFN CUSTOMERS

Customer Group	Number of Customers
Customers enrolled in the MBL Program;	248,811
Residential customers on tiered rate plans;(a)	Redundant with MBL
Energy Savings Assistance (ESA) Program participants;(b)	46,203
Customers enrolled in California Alternate Rates for Energy (CARE) Program or Family Electric Rate Assistance (FERA);	1,419,796
Customers that self-identify as having a person with a disability in the household (e.g., disabled);	41,432
Customers who self-select to receive utility communications in non-standard format (e.g., in braille or large print); and	1,199
Customers who indicate a non-English language preference.	1,542,152
Customers that self-identify as having a person in the household that uses durable medical equipment;	52,067
Customers that self-identify as having a person in the household that uses Assistive Technology;	8,329
Customers that self-identify as having a person in the household that has a hearing disability (e.g., deaf, or hard-of-hearing);	26,636
Customers that self-identify as having a person in the household that has a vision disability (e.g., Low Vision);	15,859
Customers that self-identify as having a person in the household that is blind; and	1,319
Customers that self-identify as having a person in the household that is 65+ years old.	79,046

(a) Customers enrolled in MBL program may receive an additional allotment of electricity and/or gas per month (approximately 500 kilowatt-hours of electricity or 12 percent discount if they are on an eligible electric rate, and/or 25 therms of gas per month).

(b) To qualify for the ESA Program, a residential customer's household income must be at or below 200 percent of Federal Poverty Guidelines, as per D.05-10-044. See Appendix E.

Customers who identify with one or more of the thirteen categories described above represent approximately a 30 percent distribution of our residential customer base.

Evaluating Specific Challenges and Needs During a Wildfire or PSPS Event Related to the AFN Customer Base

PG&E identifies specific customer challenges and needs during a wildfire event or PSPS by working with several stakeholder advisory councils and focus groups. During a PSPS, PG&E tracks complaints and escalations. PG&E Program Managers evaluate information received from complaints and escalations to find a path forward in addressing AFN-specific challenges experienced during a PSPS.

PG&E utilizes customer surveys to collect feedback through our PSPS Post-Event Customer Surveys, In-Event CBO Meetings, and CRC attendee surveys. PG&E elaborates on specific challenges and needs in the Annual AFN Plan[236] for PSPS Support. PG&E identifies AFN customers during a Wildfire event or PSPS and reports these counts on a quarterly basis in the AFN Quarterly Progress Reports.

People with Disabilities and Aging Council

PG&E hosts a quarterly council, People with Disabilities and Aging Advisory Council which provides a forum to gather insight into the needs of individuals with AFN related to emergency preparedness and other PG&E disability programs and services. This Council is made up of a diverse group of CBOs and PG&E leaders that supports people with developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, and older adult communities. PG&E's goal is to collaborate, discuss relevant topics, highlight progress made, and identify areas for improvement in how PG&E's existing and future activities supporting seniors and individuals with disabilities.

Joint Investor-Owned Utilities Statewide AFN Advisory Council

The Joint IOUs (PG&E, SCE, SDG&E) established the Statewide AFN Advisory Council to engage with members, advocates, and leaders representing vulnerable populations to develop strategies for helping the many constituencies served by the utilities. The Joint IOUs will convene with the Council no less than four times per year.

AFN Collaborative (Leadership) Council:

The Joint IOUs, together with state and local agency and community AFN leaders, established regular meetings to discuss how the IOUs can better identify and target AFN customers and address their needs during PSPS events. Attendees include IOU senior executives, leaders from the State Council on Developmental Disabilities, Disability Rights California, CFILC, Disability Rights Education and Defense Fund, Cal OES, CPUC, Liberty Utilities, Bear Valley Electric, and PacificCorp. PG&E will continue to meet with stakeholders to improve access to resources during PSPS events for AFN customers.

Joint IOU AFN Core Planning Team:

The Joint IOUs have created an AFN Core Planning team to develop upcoming AFN Plans. PG&E and the AFN Core Planning team follows the six steps outlined by the FEMA Comprehensive Preparedness Guide (CPG).[237,]

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236 See the most recent AFN plan and quarterly updates, available at: https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program/public-safety-power-shutoffs.html?vnt=pspsreports#tabs-6e3912efa4-item-c4f1d89b80-tab.

237 The supporting document is available at: PG&E's Community Wildfire Safety Program.

Low Income Oversight Board (LIOB):

The LIOB is a board established to advise the CPUC on low-income electric and gas customer issues and programs. PG&E engages with this board on a quarterly basis to provide information and gain input about wildfire mitigation activities, including PSPS.

Local Government Advisory Councils and Working Groups:

PG&E includes representatives from the AFN community on both the Advisory Councils and the PSPS Regional Working Groups. Additionally, PG&E hosts local wildfire safety sessions with each county OES in advance of wildfire season. PG&E's plans to ensure AFN populations are included in these sessions for awareness and opportunity for feedback.

Communities of Color Advisory Group:

PG&E solicits input from the Communities of Color Advisory Group, which assists PG&E in crafting outreach and engagement with communities of color on a variety of issues impacting diverse communities.

Addressing AFN Customer Needs Before, During, and After a Wildfire or PSPS Event

To ensure that PG&E's most vulnerable population of AFN customers receive notifications during wildfire-related emergencies and PSPS, additional notification steps are conducted to make every possible effort to ensure that MBL and SIV customers receive notifications. MBL customers have qualifying medical conditions wherein power is essential to maintain medical devices powered, and SIV customers have a serious illness or condition that could be life-threatening if they were to experience or lose power, such as losing power to a screen reader for blind and low vision or Text Telephone Device for Deaf or Hard-of-Hearing customers.

PG&E continues to deliver on its goal of making PSPS events less burdensome for our customers through partnership with the programs below:

- 23 food banks;
- 26 Meals on Wheels organizations;
- 15 Disability Disaster Access and Resources (DDAR) Centers;
- 5 Low Income Home Energy Assistance Program providers;
- 4 accessible transportation providers;
- 3 outreach organizations (In language, ASL, and Blind/Low Vision);
- The California Network of 211;
- A grocery delivery organization;
- A hot meal organization;

- A family resource center;
- A fresh produce provider;
- A portable shower/laundry service provider; and
- 38 Multi--Cultural Media Partners.

PG&E opens CRCs during a PSPS event to provide customers with basic power and other needs. PG&E describes its CRCs and the services offered at them in Section 11.5. Accommodations for customers with AFN are available, such as accessible restrooms and privacy screens for individuals who need to complete medical treatments.

In collaboration with the CFILC, the DDAR Program was launched as a joint effort to serve customers with AFN who also have medical and independent living needs and older adults. CFILC administers the program through partnerships with participating DDAR Centers in local communities throughout the PG&E service territory. DDAR enables local DDAR Centers to provide qualifying customers who use electric medical devices with access to backup portable batteries through a grant, lease-to-own, or low-interest financial loan program. DDAR uses a live intake process to understand individual customer needs, discuss emergency plan preparedness, and develop solutions for each customer during a PSPS. PSPS resources provided by DDAR include accessible transportation, lodging, food vouchers, and gas cards for generator fuel. Throughout the year, DDAR assists customers with disabilities and independent living needs with emergency planning education and outreach about PG&E programs.

PG&E has a partnership with the California Network of 211 (211) to provide customers with AFN with a single source of information and connection to available resources in their communities. 211 provides PSPS education, outreach, and emergency planning in advance of a PSPS event. The program connects those with AFN to critical resources like transportation, food, batteries, and other social services during a PSPS event. Outside of active PSPS events, 211 focuses on outreach to at-risk- customers, including those living in HFRA who are eligible for income-qualified assistance programs and rely on life sustaining-medical equipment. The focus during these times will be to evaluate these customers' resiliency plans, connect them with existing programs that can help them prepare for outages, and to assist them in completing applications for these programs.

11.4.5 Engagement With Tribal Nations

The electrical corporation must provide an overview of its process for understanding, evaluating, designing, and implementing wildfire and outage program risk initiative strategies, policies, and procedures specific for collaboration with to Tribal Nations served by the electrical corporation and on whose lands its infrastructure is located.[238] *The electrical corporation must also report on the following:*

- *Summary of key tribal demographics;*
- *Ongoing consultation and collaborative efforts performed by the electrical corporation with Tribal Nations;*
- *Evaluation of the specific challenges and needs during a wildfire or PSPS event of the electrical corporation's Tribal Nation customer base; and*
- *Plans to address specific needs of the tribal customers throughout the service territory specific to the unique threats that wildfires and PSPS events may pose for those populations before, during, and after the incidents. This should include high-level strategies, policies, programs, and procedures for outreach, engagement in the development and implementation of the tribal-specific risk initiative strategies, and ongoing feedback practices.*

The electrical corporation must reference the Tracking ID where appropriate.

Tracking ID: N/A

PG&E works directly with Tribal Liaisons and with tribal customers throughout the service territory to understand the unique threats and needs of those populations before, during, and after incidents such as a PSPS. PG&E conducts specific outreach and engagement to educate tribal customers about wildfire mitigation and the program offerings that are available.

Summary of Key Tribal Demographics

Pursuant to the Native American Heritage Commission as of 2024, within the service area, there are: 62 federally recognized tribes, 52 non-federally recognized tribes, 58 reservations and 21 Tribal Health Facilities. According to the United States Census and direct tribal outreach, PG&E understands that the tribal nation population within the service area is approximately 40,712, excluding tribal members living in urban populations.

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[238] *Pub. Util. Code § 8386(c)(19).*

CWSP Tribal Engagement Overview

In response to wildfire challenges, planned outages, and unplanned outages faced by tribes, PG&E conducts outreach to Tribal governments in our service area. Tribal governments are made aware of the various programs that are available to mitigate the challenges faced by tribal customers, promote awareness and education regarding our programs and services, and partner with tribal governments to provide safe and reliable electricity to their communities. During the outreach, tribes are given an opportunity to comment on upcoming wildfire mitigation plans and current mitigation plans. The following is a list of recurring and ongoing outreach conducted and maintained by PG&E with the support of PG&E's Tribal Liaisons:

- Tribal Contact List outreach;
- Tribal Community Wildfire Safety Webinar;
- Tribal Grant Program Review;
- Tribal Newsletter to all Tribes; and
- Tribal SharePoint.

PG&E's Tribal Liaisons are in continuous communication with tribal governments throughout the service territory specifically to help address the specific needs and unique threats that wildfires and a PSPS may pose. See Section 11.5 for more information.

11.4.6 Current Gaps and Limitations

In tabulated format, the electrical corporation must provide a list of current gaps and limitations in its public communication strategy, including any notification failures identified in the most recent PSPS post-season report. Where gaps or limitations exist, the electrical corporation must indicate the remedial action plan and the timeline for resolving the gaps or limitations. For all requested information, the electrical corporation should indicate a form of verification that can be provided upon request for compliance assurance.

Table 11-11 below explains our key gaps and limitations in public emergency communication strategy.

TABLE 11-11:
KEY GAPS AND LIMITATIONS IN PUBLIC EMERGENCY COMMUNICATION STRATEGY

Gap or Limitation Subject	Brief Description of Gap or Limitation	Remedial Action Plan
Errors in Automated Messaging deployment	During a PSPS event, at time of de-energization, the process of deploying notifications to customers about current state of service to their location switches from a manual process with human actions to prep, stage and deploy notifications, to an automated system that is utilized for all outage communications. In certain cases, logic used for normal outage communications interfere with the automation of these messages, causing incorrect notifications, or no notification at all	Strategy: Work with OMT SME's and program administrators to identify edge cases, like abnormal circuit configurations, mis-mapped customers, and tools put in place to avoid duplicate messages to customers during blue sky outage communications. Target Timeline: Communications around conflicts/issues with OMT Program team began when issue was known. Remedial actions put in place to correct (if possible) at that time. New processes and auditing tools put in place in December 2024 to review playbooks prior to sending notifications to attempt corrections, and validate service activity and notification preferences. Mis-mapped customers reviewed by Operations to correct data for proper transformer assignment at conclusion of each event.
Notification Vendor performance	During several events, the vendor used for deploying PSPS notifications mishandled or disregarded files that needed to be processed/delivered, resulting in missed notifications to customers	Strategy: Ongoing dialog with Message Broadcast to identify root causes of missed notifications. Meeting on 12/6/24 with Message Broadcast leadership in San Ramon to discuss notification failures and re-commitment from them to drive errors and miscommunication out of process. Payload testing and drills identified for Spring/Summer 2025 to practice and ensure readiness for PSPS events. Target Timeline: By 7/1/25, conduct exercises and drills to determine that that file handling and notification deployment will be acceptable to meet PSPS compliance requirements on all notification requirements.

The above table does not include a complete list of all notification failures identified in the most recent PSPS post-season report as it has not been filed prior to pre-submission of 2026-2028 WMP.

11.5 Customer Support in Wildfire and PSPS Emergencies

In this section, the electrical corporation must provide an overview of its activities (programs) systems, and protocols to support residential and non-residential customers during and after wildfire emergencies and PSPS events.[239] The overview for each emergency service must be no more than one page. The overview must cover the following customer emergency services:

- *Outage reporting;*
- *Support for low-income customers;*
- *Billing adjustments;*
- *Deposit waivers;*
- *Extended payment plans;*
- *Suspension of disconnection and non-payment fees;*
- *Repair processing and timing;*
- *List and description of community assistance locations and services;*
- *MBL support services; and*
- *Access to electrical corporation representatives.*

The electrical corporation must reference the Tracking ID where appropriate.

Tracking ID: PS-12

AFN Customer Support During PSPS Emergencies: Improve access to portable battery storage solutions and in-event support including hotels, transportation, food vouchers, and fuel cards for AFN customers impacted by PSPS and Wildfire outages. See PS-12 in Table 11-11 in Section 11.1.1 for more information.

When a wildfire or PSPS event occurs, PG&E works with lead agencies such as CAL FIRE and OES to determine the appropriate assistance programs based on community needs and guidance from the lead agency, including support for AFN and MBL customers. CRCs are used where applicable. PG&E evaluates the scope of the event and partners with CBOs to activate services based on the wildfire or PSPS footprint and estimated customer impact. See PG&E's 2025 AFN Plan for a list of current community assistance partnerships. The programs, systems, and protocols listed below are available during PSPS events and wildfires.

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[239] *Pub. Util. Code, § 8386(c)(21).*

Outage Reporting

During wildfires, PG&E follows the established emergency communication framework outlined in the CERP and GO 166 standards.[240] PG&E uses notification systems to alert customers and public safety partners of planned or unplanned electric outages stemming from de-energizations requested by the responding agency (i.e., CAL FIRE) or outages caused by the wildfire itself as those related to wildfires. PG&E sends automated notifications via call, text message, and e-mail to notify recipients of major events affecting their area and at key milestones (see Section 11.4.2, Figure PG&E-11.4.2-1) in the outage and restoration process. Notifications provide incident-related updates if long-duration outages are anticipated, which may include the cause of the outage, estimated restoration times, and notification once power is restored (where possible). Customers with language preferences selected in their PG&E accounts receive in-language notifications. If a customer has notification preferences set to receive outage-related updates, that customer will receive automated notifications with the status of the outage.

Support for Low-income Customers

PG&E provides support for low-income customers impacted by wildfires, including freezing CARE eligibility standards and high usage post-enrollment verification requests, increasing the assistance cap for emergency assistance program, and modifying qualification requirements for the ESA Program by allowing customers to self-certify that they meet income qualifications. PG&E leverages its CARE community outreach contractors to inform customers of the support and resources available to them. Additionally, PG&E coordinates with the program administrator of the Relief for Energy Assistance Through Community Help (REACH), a PG&E and customer-funded emergency assistance program, to request increasing the assistance cap amount for red-tagged customers. Red-tagged customers are those who have lost their homes due to a fire. These customers will receive a letter indicating that their homes have been red-tagged and they can receive assistance from different services. The REACH assistance allows customers who lost their homes to receive additional financial assistance to pay their current utility bill or to set up new service. PG&E informs all REACH agencies of this financial support for customers. See Section 11.4.3, Table 11-10, and Section 11.4.4, under Addressing AFN Customer Needs Before, During, and After a Wildfire or PSPS Event, for income-qualified event-specific assistance and or support.

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[240] GO 166, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M464/K730/464730514.pdf.

Billing Adjustments

Discontinue Billing and Prorate Minimum Delivery Charges

If a customer's service has been disrupted or degraded because of wildfire, their billing is discontinued without the assessment of a disconnection charge. PG&E also prorates any monthly access charge or minimum charges for affected customers.

Stop Estimated Usage for Billing Attributed to the Period When a Home/Unit Was Unoccupied Due to a Disaster

During natural disasters, PG&E identifies general areas that were evacuated and reassesses its approach for any bills in the area requiring estimation.

In accordance with the Emergency Consumer Protection Plan (D.19-07-015),[241] PG&E allows customers whose homes or businesses were red tagged and had been served under a rate that has since been closed to new customers, to reestablish service under their prior rate schedule at their current location or an alternative location, regardless of the current applicability of their prior rate schedule, as long as the rate schedule is still available and has not been retired.[242] D.19-07-015 also requires PG&E to expedite move-in and move-out service requests for affected customers.[243] PG&E expedites these requests based on the date requested by the customer,[244] consistent with our Emergency Consumer Protection Plan.[245]

Deposit Waivers

PG&E waives security deposit requirements to re-establish service for customers whose home(s) or small business(es) were destroyed by a disaster. In addition to offering this protection, PG&E, in accordance with D.20-06-003 does not require the re-establishment of service deposits from residential customers.

Extended Payment Plans

Following a disaster, PG&E offers impacted and red-tagged customers the most lenient payment arrangement term, which requires a 20 percent down payment with a repayment period of 12 months for red-tagged customers and a 20 percent down payment with a repayment period of eight months for impacted accounts. All residential

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241 D.19-07-015, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K821/309821775.PDF.

242 The Commission approved PG&E's proposal in AL 4014-G/5378-E to revise Electric Rule 12 to allow customer to reestablish service under a prior rate schedule as part of our Emergency Consumer Protection Plan. See Appendix E.

243 D.19-07-015, pp. 58-59, Conclusion of Law 14. See Appendix E.

244 This does not include any meter sets, including multi-unit meter sets or any other requests that require inspections, and/or criteria as required in the PG&E Electric and Gas Service Requirements Handbook.

245 The supporting document is available at: PG&E's Community Wildfire Safety Program.

customers are eligible for payment arrangements up to a 24-month pay plan in accordance with D.23-08-049. Customers are eligible to pay off their arrearage sooner if preferred. In addition, customers who indicate that their employment was impacted by the disaster are also eligible for favorable payment plans.

Suspension of Disconnection and Non-Payment Fees

PG&E suspends disconnections for all red-tagged customers for up to 12 months after a Governor or President's emergency proclamation. PG&E waives security deposits as described previously in the Deposit Waiver section above and does not charge late fees.

Repair Processing and Timing

PG&E offers repair processing and timely assistance to utility customers pursuant to Pub. Util. Code Section 8386(c)(21). PG&E works with impacted customers to communicate priorities and timelines for repairs and restoration. Specifically, PG&E sends a letter to red-tagged customers informing them of the services available through Consumer Protections. The letter provides contact information and related support with PG&E, including information on the process for receiving temporary power. In addition to contacting red-tagged customers via letter notices, impacted customers have access to utility representatives through multiple channels, such as PG&E's call center, public affairs, customer account representatives, and field teams.

List and Description of Community Assistance and Services

<u>Community Resource Centers</u>

During a wildfire or PSPS event, PG&E will open CRCs where community members can access basic resources including:

- A safe location to charge electronic devices and medical equipment;
- Up-to-date information about the wildfire or PSPS event; and
- Bottled water, snacks, blankets, Americans with Disabilities accessible restrooms, and Wi-Fi.

Additionally, indoor CRCs have heating/cooling, bagged ice, and privacy screens for nursing mothers. PG&E continues to enlarge its portfolio of contracted CRC locations, including indoor and outdoor sites, which can be quickly opened when needed. Sites were identified in collaboration with counties, Tribal governments, and other key stakeholders and are reviewed annually. PG&E has 118 indoor sites and 286 outdoor sites as of January 31, 2025.

PG&E evaluates the scope of the emergency or event and proposes CRC sites to activate based on forecasted customer impact. Once the proposed sites are approved by impacted counties' Offices of Emergency Management and impacted Tribal governments, PG&E takes the required steps to make the sites operational.

PG&E's website lists CRCs by county and provides details on the resources available at each CRC. Each CRC location is also included on the outage map, so visitors can easily identify which CRC is closest to them by looking up their address. PG&E also communicates CRC site locations through press releases, social media posts, and local government outreach. Lastly, customer text and e-mail notifications include a hyperlink to PG&E's PSPS webpage, where customers can find all relevant CRC information.

Backup Power Programs

PG&E continues to deliver on the goal of making PSPS events less burdensome for customers by offering a suite of backup power programs. PG&E has made a strategic shift over the past two years, transitioning from portable to permanent solutions, which provide longer outage support. PG&E continues to explore opportunities to develop and expand our offerings. Below is a summary of current programs.

- Fixed-Power Solutions (FPS): PG&E launched the FPS initiative in 2022 to support permanent, long-term backup power solutions for customers frequently impacted by wildfire safety outages. PG&E significantly scaled the residential FPS offering in 2023 and 2024, installing nearly 2,000 permanent batteries to help ensure the risks of wildfire safety outages are minimized for the most impacted residential customers. The non-residential portion of FPS offers technical assistance and financial incentives for K-12 schools and critical facilities to help reduce the cost of backup power equipment and installations. Both the residential and non-residential FPS programs will continue to be offered to the most impacted customers.

- Permanent Battery Storage Rebate Program: PG&E provides permanent battery storage rebates to targeted customers who are heavily impacted by wildfire safety outages.

- Generator and Battery Rebate Program: PG&E provides rebates for portable generators and batteries to qualified customers who reside in Tier 2 or 3 HFTDs or served by an EPSS circuit. Customers are eligible for a higher rebate if enrolled in PG&E's CARE or FERA program.

- Backup Power Transfer Meter (BPTM): PG&E installs the BPTM device for customers who reside in Tier 2 or 3 HFTDs or served by an EPSS circuit. The BPTM device is a meter that is also a transfer switch that automatically connects power to a generator when it detects the grid is offline and switches back to the utility once the grid is back on.

- Self-Generation Incentive Program (SGIP): As an SGIP Program administrator, we provide financial incentives for targeted customers to install permanent battery storage, with a focus on supporting qualified customers in HFTDs, and who have been affected by EPSS and PSPS events.

- Portable Battery Program: PG&E works with CBOs to provide portable backup power solutions for our MBL and SIV customers who are frequently impacted by PSPS and EPSS outages.

- Disability Disaster Access & Resources Program: PG&E works with the CFILC to provide PSPS support through the delivery of portable batteries to power critical devices during PSPS events. The DDAR Program also provides in-event support for electricity dependent customers with AFN by offering hotel stays, food stipends, transportation, and generator fuel cards. This program contributes to PS-12.

MBL Support Services

- MBL Marketing, Education, and Outreach: the MBL Program is an assistance program for residential customers who require extra energy needs due to qualifying medical equipment and conditions. PG&E encourages customers to participate in the MBL Program throughout the year through targeted acquisition e-mails and letters, digital media advertisement, as well as radio ads. Pursuant to D.20-06-003, PG&E, along with other IOUs with MBL programs, provides annual MBL training to In-Home Support Services providers before the end of the first quarter each year.

  PG&E will continue using all available communication channels prior to and during PSPS, including phone calls, texts, and e-mail notifications to notify potentially impacted MBL customers. Potentially impacted MBL customers may receive doorbell rings if they do not acknowledge notifications before PSPS. To ensure that PG&E has accurate customer contact information, PG&E will send out Contact Information Update reminder postcards and e-mail to MBL customers in the HFRA who may be impacted by PSPS, prior to wildfire season in 2025. PG&E will continue to identify and reach out to MBL customers in the HFRA who have missing or invalid information through a variety of channels to update or obtain contact information.

- D-MEDICAL 12 percent Discount for Non-Tiered Electric Rates: Historically, the financial benefits received by PG&E's MBL customers have only been available to customers taking service on a tiered rate schedule like PG&E's default Time-of-Use (TOU) rate, Schedule E-TOU-C, or its simple tiered (non-TOU) rate, Schedule E-1. This is because the financial benefits were provided to MBL customers solely via augmented baseline allowances that are applicable only to tiered rates.

  PG&E implemented D-MEDICAL to coincide with the launch of its new electrification rate, Electric Home (Schedule E-ELEC), both for Net Energy Metering (NEM) and non-NEM customers, and for E-TOU-D customers by the end of 2023. On December 1, 2024, PG&E will be implementing the final phase of DMEDICAL discount and implementing the discount for its customers taking service on EV-2 rate.

- Joint IOU MBL Eligible Population Study: On September 24, 2021, the CPUC issued Resolution E-5169 to implement improvements to the MBL programs of the Large Utilities. The Large Utilities have retained a vendor to conduct an MBL Study, which will support and propose new enrollment goals for the next five years for the MBL Program and medical discounts on non-tiered rates, as well as and how often to update the MBL Study, the process for developing these updates, and the process for setting future enrollment goals.

Access to Electrical Corporation Representatives

PG&E has five regions, each of which has a Regional Vice President (RVP) who addresses the local community needs of each region. One of the primary functions of each RVP is to host regionals townhalls and CWSP webinars throughout the year. Customers are provided an opportunity to submit real-time questions around a variety of wildfire safety and general PG&E topics. In addition, many PG&E leaders have a social media presence on several platforms and encourage and receive actionable feedback. Our Customer Relations Department escalates concerns to executive level leadership where necessary.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 12

ENTERPRISE SYSTEMS

12. Enterprise Systems

In this section, the electrical corporation must provide an overview of inputs to, operation of, and support for various enterprise systems it uses for VM, asset management and inspection, grid monitoring, ignition detection, weather forecasting, and risk assessment initiatives.[246] *Enterprise systems encompass structures and methods that allow the electrical corporation and its employees and/or contractors to accept, store, retrieve, and update data for the production, management, and scheduling of related work.*

12.1 Targets

In this section, the electrical corporation must provide qualitative targets for each year of the 3-year WMP cycle. The electrical corporation must provide at least one qualitative target for each initiative as related to implementation and improvement of its enterprise systems.

12.1.1 Qualitative Targets

The electrical corporation must provide at least one qualitative target for each relevant initiative (VM, asset management and inspection, grid monitoring, ignition detection, weather forecasting, and risk assessment) in its 3-year plan for implementing and improving its enterprise systems, including the following:

- *Identification of which initiative(s) and activity/activities in the WMP the electrical corporation is implementing to achieve the stated target, including Tracking IDs and the previous tracking ID used in past WMPs, if applicable;*
- *A target completion date; and*
- *Reference(s) to the WMP section(s) or appendix, including page numbers, where the details of the target(s) are documented and substantiated.*

Tracking ID: ES-01; ES-02; ES-03; ES-04; ES-05

Enterprise Systems targets are described below.

- VM critical datasets data quality remediation (ES-01) (Vegetation Management):

  This effort improves VM data through proactive identification of data quality issues and the development and execution of data quality mitigation plans. PG&E's data

[246] *Pub. Util. Code § 8386(c)(10), (14), (18).*

management practice will use enterprise data standards to identify critical datasets essential for VM execution and establish profiling and monitoring to identify issues. PG&E will establish process and cadence to determine root causes of issues and to prioritize and begin remediation activities. As systems, programs, and performance indicators change over time, we will review and prioritize our most critical datasets and remediations. See Revision Notice Response to Critical Issue RN-PGE-26-08 for additional information.

- Evaluate and create new method(s) to improve the accuracy of asset inventory data (ES-02) (Asset Management and Inspection):

  This effort involves the design, development, and evaluation of methods to validate the accuracy of asset inventory data. The outcome of the effort will be a strategic and systematic approach to performing accuracy validation exercises, and the direct outputs will include evaluation results for all methods and action plan(s) to operationalize the method(s) found to be successful.

- Grid monitoring systems efficacy assessment (ES-03) (Grid Monitoring):

  This effort involves the development of methodologies to assess the efficacy of PG&E's continuous grid monitoring systems to deliver accurate alerts at scale that can be utilized to take proactive measures that reduce/eliminate ignition risks and improve electric system reliability. These methodologies will (a) enable PG&E to have insight into a sensor system/sub-system's availability which in turn can provide confidence that the presence/absence of alerts is a true indication of grid health, and (b) validate the ability of the system to identify faults/spots with potential incipient failure with locational accuracy for optimized patrols/field investigations. The outcome of the effort would be reports that will inform action plans for identified improvements in sensor alert processing as well as technology enhancements.

- Weekly uptime of wildfire cameras (SA-15) (Ignition Detection):

  See Section 10.4.1 Existing Ignition Detection Sensors and Systems for additional information.

- Participate in company disaster recovery exercise (ES-04) (Weather Forecasting):

  Meteorology Operations and Fire Science will participate in a company disaster recovery exercise and test the failover capabilities of PG&E's AWS-cloud Meteorology Enterprise System.

- Integration of continuous grid monitoring technologies (ES-05) (Risk Assessment):

  This effort involves integration of continuous grid monitoring technologies that deliver enhanced situational awareness into existing PG&E enterprise systems. All existing and new sensor asset families will be added in PG&E's GIS databases for asset inventory and location visibility purposes. A centralized dashboard will be created to streamline monitoring of availability and performance of field-based sensors instead of being tracked through disparate methods using isolated management systems. Methodologies that can evaluate raw alerts from field sensors and assign priorities will be developed and actionable tasks delivered to

PG&E Operations. A system will be designed and developed to enable historical trending of alert evaluations vs. field findings that will enable further refinement of methodologies for improved efficacy.

PG&E's targets for Enterprise Systems for the WMP period are shown in Table 12-1 below.

- Reporting: PG&E will use the targets in Table 12-1 below for quarterly compliance reporting including the QDR, QN, and the ARC. We note that throughout this 2026-2028 WMP, we discuss current plans for wildfire-related activities beyond the targets in 11-1. The timing and scope of these additional activities may change. We will not be reporting on these activities in our QDR, QN, or ARC because they are not defined targets but are described in our 2026-2028 WMP to provide a complete picture of our wildfire mitigation activities.

- External Factors: All targets throughout this WMP are subject to External Factors. External Factors represent reasonable circumstances that may impact execution against targets including, but not limited to, physical conditions, environmental delays, landowner or customer refusals or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, wildfires, exceptions or exemptions to regulatory/statutory requirements, and other safety considerations.

- Utility Initiative Tracking IDs (Tracking IDs): We are including Tracking IDs in each section that has associated targets. Table 12-1 displays the Tracking IDs we are implementing to tie the targets to the narratives in the WMP. The Tracking IDs will also be used for reporting in the QDR.

TABLE 12-1:
ENTERPRISE SYSTEMS TARGETS

Initiative	Activity (Tracking ID #)	Previous Tracking ID (if Applicable)	2026 End-of-Year Total/Completion Date	2027 Total/Status	2028 Total/Status	Section; Page Number
Enterprise System – Vegetation Management	VM Critical Datasets Data Quality Remediation (ES-01)	n/a	Started; January 2026[(a)]	In Progress; 2027[(a)]	Completed; December 31, 2028[(a)]	12.1.1; p. 544
Enterprise System – Asset Management and Inspection	Evaluate and create new methods(s) to improve the Accuracy of Asset Inventory Data (ES-02)	n/a	Started; March 2026	In Progress; 2027	Completed; December 31, 2028	12.1.1; p. 544
Enterprise System – Grid Monitoring	Grid Monitoring Sensor Systems Efficacy Assessment (ES-03)	n/a	Started; March 2026	In Progress; 2027	Completed; December 31, 2028	12.1.1; p. 544
Enterprise System – Weather Forecasting	Participate in Company Disaster Recovery Exercise (ES-04)	n/a	Completed; December 31, 2026	n/a	n/a	12.1.1; p. 544
Enterprise System – Risk Assessment	Integration of continuous grid monitoring technologies (ES-05)	n/a	Started; March 2026	In Progress; 2027	Completed; December 31, 2028	12.1.1; p. 544

(a) See 2026-2028 WMP Revision Notice Response R0, Critical Issue response RN-PGE-26-08 for additional information.

12.2 Summary of Enterprise Systems

Electrical corporations must provide a summary narrative of no more than three pages that discusses how its enterprise systems contain, account, or allow for the following:

- *Any database(s) the electrical corporation used for data storage;*
- *Internal procedures for updating the enterprise system, including database(s), any planned updates, and the ability to migrate data across systems and ensure accuracy if necessary;*
- *The electrical corporation's asset identification process;*
- *The electrical corporation's process for integrating 100 percent asset identification or its justification if not currently in place;*
- *Processes to ensure data integrity (accuracy, completeness, and quality of data), accessibility (ability of the electrical corporation to access data across formats and locations), and retention (any policies the electrical corporation for how long it stores data and how it disposes of data after any retention period);*
- *Any Quality Assurance (QA)/Quality Control (QC) or auditing of its system;*
- *Overview of any data governance plan that the electrical corporation has in place. Highlighting any data stewardship practices;*
- *How current WMP initiatives and activities are being tracked and monitored in enterprise systems;*
- *Employee and/or contractor ability to access and interact with the data and systems for tracking work order status and scheduling;*
- *How the electrical corporation's work order and asset management systems feed into risk analysis and alternative or interim activity selection; and*
- *Any changes to the electrical corporation's enterprise systems since the last Base WMP submission and a brief explanation as to why those changes were made. Include any planned improvements or updates to the enterprise systems and the timeline for implementation.*

In this section we provide a summary of Enterprise Systems.

- <u>Databases</u>: PG&E uses several databases or data platforms designed to handle diverse data requirements of PG&E's wildfire mitigation technology. Key databases primarily supporting wildfire mitigation technology include: Geospatial, Telemetry, Asset Management, Incident Management, Customer Information, and Data Analytics Platform. For example: Each asset in the asset registry must have an established system of entry. The preferred systems of entry are Electric GISs, specifically Electric Transmission Geographic Information System and Electric Distribution Geographic Information System. Additionally, these systems capture and record the spatial location and electrical connectivity of the assets.

- Internal Procedures: PG&E has an Information Technology (IT) Management of Change (MOC) procedure. It is a structured approach to make changes or updates to the enterprise systems. This procedure specifies that changes or updates are planned, assessed for potential impacts, tested, and coordinated with relevant stakeholders. The primary goal of the MOC procedure is to obtain the necessary approvals while minimizing the risk to production enterprise systems and business processes. The approach to data migration is tailored to each project, adjusting to the varying levels of complexity involved. For example, in the One VM system, the data migration framework and strategy are designed to understand and identify the data migration scope, undertake data cleansing, data transformation, and data mapping activities. It also includes steps for data validation and data quality assessment, followed by data migration to the production environment.

- Asset Identification Process: In accordance with International Organization for Standardization (ISO) 55001 international asset management standards, PG&E asset management system standards[247] require the risk, performance and cost of electric operations assets and the supporting information systems to be managed. The assets under management are defined by the standards and require that the inventory and critical attributes of those assets be managed in electric Asset Registry systems (e.g., GIS, SAP). As new asset types are identified and put into service, those assets are also required to be added to the Asset Registry systems. As part of our electric asset data management program, which is certified under ISO 55001, PG&E has developed standards, programs, processes and controls to ensure the integrity of its electric asset data. Foundational to this program is the Asset Registry Data Management Standard, which outlines required practices spanning the data lifecycle from the ingestion of newly created asset records to the remediation of historic data records to record retirement.

  Electric asset identification is enabled through execution of programs consistent with this standard, including:

  1) As-Built Program: This program enables systematic ingestion into our Asset Registry database (GIS) of traceable, verifiable, accurate and complete data for all newly constructed assets and assigns unique identifiers for each asset. The As-Built Program consults with Asset Management to identify assets for which attributes must be collected, reported and updated in the Asset Registry. Assets are selected based on whether they require inspection, maintenance or are involved in risk modeling.

  2) Data Remediation Programs: PG&E also identifies assets through programs designed to improve the accuracy of its asset data. The Map Correction program partners with frontline workers (e.g., inspectors) to leverage field-based observations to correct legacy inaccuracies in asset-related data,

[247] The supporting documents are available at: PG&E's Community Wildfire Safety Program.

including identification of in-field assets that are missing from the Asset Registry. The Data Remediation program develops projects that target specific data gaps/inaccuracies through field or desktop research, records research or applied analytics. These projects may also include deployment of new technologies, procedures or processes needed to remediate the root cause data quality issues and avoid recurrence.

- Total Asset Integration: PG&E interprets OEIS guidance as referring to the process or programs used to integrate critical asset-related datasets. Since 2020, PG&E has been systematically integrating and providing access to its most critical electric asset and wildfire related data in our Enterprise analytics platform – Palantir Foundry.[248] This program enhances our ability to make risk-informed, data-driven decisions for critical wildfire related programs such as PSPS, EPSS, and asset risk quantification. As part of this program, PG&E has integrated physical asset, operational, lifecycle, and environmental data from over 50 existing disparate, purpose-built data systems into Palantir Foundry. PG&E's recent focus has been integrating Asset Registry data with asset condition and asset operating history data for risk-prioritized asset types. The data integration work provides enterprise-wide access to reusable, high-quality, governed and integrated electric asset data. These foundational datasets are then used to build analytic tools that support a variety of analyses and applications, including situational awareness, asset health assessment, wildfire risk mitigation programs and WMP regulatory reporting (e.g., OEIS Spatial Quarterly Data Reporting). PG&E's asset data is also integrated through core system-to-system integrations (e.g., GIS to SAP integrations) where Asset Registry information from GIS is needed in other systems to manage workflows. A program has been implemented to monitor the fidelity of the electric asset data integration between GIS to SAP.

- Data Integrity: The Enterprise Data Management Policy (GOV-09)[249] formalized PG&E's goal of effectively and accurately managing data as an asset by implementing and maintaining an Enterprise Data Management Program. Functional Areas operationalize programs to conform with these policies addressing integrity, accessibility, and retention as exemplified by the Electric Asset Management program portfolio detailed above in Total Asset Integration. PG&E also established metrics for electric data asset management to measure data management maturity and the quality of critical data assets. These metrics are calculated using sub metrics measuring the extent to which: (1) critical data has been identified; (2) ownership for critical data has been identified; (3) data quality rules for critical data have been identified; and (4) critical data aligns to data quality rules. This helps to ensure that PG&E has practices in place that enable good quality data and that the data quality is, in fact, good. The metrics also look at a broader, company-wide level of tracking critical data under management. This is tracked in a tactical year-by-year perspective, but also an overall goal perspective.

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248 For more information, see Palantir's website, available at: https://www.palantir.com/platforms/foundry/.

249 The supporting document is available at: PG&E's Community Wildfire Safety Program.

Data remediations at the tactical level are also being tracked to show how data quality is being improved.

- System QA/QC: PG&E Test Center of Excellence has established test processes, procedures, standards, and guidelines. PG&E has an IT MOC procedure which ensures that application teams are responsible for testing changes before scheduling them in production enterprise systems.

- Data Governance Plan: See Data Integrity above.

- WMP Initiative Tracking: PG&E's WMP initiatives are tracked and monitored in Palantir Foundry and Excel.

- Employee/Contract System Access: MyElectronicAccess (MEA)[250] is PG&E's enterprise-standard identity governance and administration system. It is used by PG&E employee and contractors to submit and track access requests to PG&E data applications and systems. MEA also provides capabilities to approve access requests, perform access reviews, and manage MEA governed roles and entitlements. Additionally, MEA provides reporting capabilities to support business, compliance, and auditing processes.

- Work and Asset Management System Feed Into Risk Model: PG&E's wildfire risk model is made up of the Ignition Consequence model and the Ignition Probability model. The Ignition Consequence model is constructed from annually generated weather and fire behavior analysis datasets. The Ignition Probability models, depending on the subset, are built using annually generated datasets for weather, vegetation, equipment failures, equipment geo-location, and other characteristic values. These datasets come from PG&E's work order and asset management systems. Provenance information, including its original source and generation date(s), is documented for each dataset used for building a WDRM version release. The provenance information is included in the WDRM Version documentation and is also published with its online implementation for end-users in Palantir Foundry. The Wildfire Risk Models provide the different level of risk mitigation effectiveness at the program level for alternative solutions that are considered. In addition, the risk model takes into account the cost to implement. This functionality then allows the user to compare cost benefit ratio across mitigation alternatives. This allows a user to make informed mitigation alternative tradeoffs.

250 The supporting document is available at: PG&E's Community Wildfire Safety Program.

- <u>Changes to Enterprise Systems</u>: Multiple system enhancements have been implemented since the last WMP submission. VM enhancements include updates to improve data quality, document reasons for removal, and improved program record keeping. Continued investments in PG&E’s wildfire technology over the 2026-2028 WMP will focus on enabling business capabilities in several key programs in the Data, Analytics & Insights, Event Management, Engineering & Work Management, System Planning & Asset Management, Customer Experience & Insights value streams, as well as in areas that may require delivery of technology solutions where additional research is required, that will drive more informed risk analysis and more agile and real-time PSPS scoping capabilities.

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

SECTION 13

LESSONS LEARNED

13. Lessons Learned

An electrical corporation must use lessons learned to drive continual improvement in its WMP.[251] *Electrical corporations must include lessons learned due to ongoing monitoring and evaluation initiatives, collaboration with other electrical corporations and industry experts, PSPS or outage events, and feedback from Energy Safety and other regulators.*

13.1 Description and Summary of Lessons Learned

In this section, the electric corporation must provide a brief narrative describing the key lessons learned tied to feedback from government agencies and stakeholders, collaboration efforts with other electrical corporations, areas for continued improvement, PSPS or outage events, and outcomes from previous WMP cycles.

The narrative must also include lessons learned from prior catastrophic wildfires ignited by the electrical corporation's facilities or equipment and findings from Energy Safety compliance audits and reports.

For each lesson learned, the electrical corporation must identify the following in Table 13-1:

- *The year of the Base WMP cycle the lesson learned was identified;*
- *Category and specific source of lesson learned;*
- *Brief description of the lesson learned that informed improvement to the WMP;*
- *Brief description of the proposed improvement to the WMP and which initiative(s) or activity/activities the electrical corporation intends to add or modify;*
- *If applicable, a brief description of how the lesson learned ties to implementation of a corrective action program;*
- *Estimated timeline for implementing the proposed improvement;*
- *If applicable, reference to the documentation that describes and substantiates the need for improvement, including:*
  - *Where relevant, a hyperlinked section and page number in the appendix of the WMP;*
  - *Where relevant, the title of the report, date of report, and link to the electrical corporation web page where the report can be downloaded; and*

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[251] *Pub. Util. Code §§ 8386(a) & (c)(5), (22).*

- *If any lessons learned were derived from quantifiable data, visual/graphical representations of these lessons learned in the supporting documentation.*

Our 2026-2028 wildfire mitigation strategy is influenced by our response to lessons learned from various sources. These sources include:

- Ongoing internal monitoring and evaluations initiatives:
  - We continue to reinforce and expand our situational awareness, customer outreach and support, and refine operational practices to reduce wildfire potential and impacts to customers.
- Feedback from Energy Safety, industry experts, and other stakeholders:
  - We are enhancing our risk modeling, fire consequence modeling, operational practices, and reporting (e.g., remediations for tracking and reporting identified by the CPUC and Energy Safety).
  - We are collaborating with other electrical corporations to share best practices

Lessons learned from past catastrophic fires are summarized in Table PG&E-4.2-1. Lessons learned from PSPS events since the last WMP cycle are discussed in Section 7.

TABLE 13-1:
LESSONS LEARNED

Year of Lesson Learned	Subject	Category and Source of Lessons Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
2023	Undergrounding and System Hardening process efficiency	Cost and process efficiency opportunities <u>Source</u>: internal continuous improvement effort	Program cost savings can be achieved through multiple mechanisms, such as lump sum contracts with vendors, and updating standards, such as spoils management and trench depth.	Negotiate and structure contract terms with undergrounding and system hardening vendors to support more cost-effective services; Updated standard for the handling and testing of spoils to maximize efficiencies; updated standard for trench depth that provide exceptions for 24” depth in approved cases with hard rock excavation.	2024 and 2025	N/A
2023-2024	Undergrounding project management improvement	Enhancing the customer experience <u>Source</u>: customer feedback	We can improve the customer experience and optimize project schedules by engaging with customers earlier and regularly throughout an underground project.	Increased and enhanced customer communication channels and cadence based on key project milestones.	2024 and 2025	N/A
2023-2024	Continuous focus on safety	Safety Standards <u>Source</u>: internal continuous improvement effort	Contractor safety requirements can help prevent third-party dig ins to utilities.	Establish requirements for all contractors to develop and implement a Dig In Prevention procedure that aligns with PG&E’s Damage Prevention procedure.	2025	N/A

**TABLE 13-1:
LESSONS LEARNED
(CONTINUED)**

Year of Lesson Learned	Subject	Category and Source of Lessons Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
2023	Improve inspection and remediation process	ACI – Addressing Risk from Hazard Trees Benchmarking	Considerations for remote sensing technologies may enable improved monitoring and identification of risk	Evaluate remote sensing technologies to inform inspection and remediation processes	2025-2026	ACI PG&E-23B-15
2024	Real-time monitoring	Sensing intelligence to inform patrol and restoration and causal evaluations Source: internal continuous improvement effort	Installation of Gridscope technology has provided enhanced intelligence on outage locations and in at least 10 instances has identified hazards prior to an outage and associated ignition.	Continue scaling the use of Gridscope as part of a real-time monitoring strategy that provides multi-sensor intelligence prior to ignition risk and supports monitoring of asset degradation.	2025-2028	N/A
2024	Feedback from Energy Safety, CPUC, or other authoritative bodies	ACI – Reduce customer impact from EPSS	The EPSS Program has seen initial data results that demonstrate there is an improved reliability pick up where vegetation and animal mitigation work is performed. Additionally, the program has identified a customer group that has experienced more than five EPSS outages, year-over-year, since the expansion of the program in 2022.	The EPSS Program will maintain a focused effort on vegetation and animal mitigation work on circuit zones with a high frequency of vegetation or animal cause. The program will also enhance its efforts to target additional outage mitigation or direct customer support for those customers that have been most impacted.	2025-2028	ACI PG&E 25U-06

TABLE 13-1:
LESSONS LEARNED
(CONTINUED)

Year of Lesson Learned	Subject	Category and Source of Lessons Learned	Description of Lesson Learned	Proposed WMP Improvement	Timeline for Implementation	Reference
2024	Internal monitoring and fault detection	ACI – Operations	The leading fault type for all outages that result in ignitions during EPSS protection continues to be from high impedance fault conditions. Since 2022, PG&E has deployed DCD capability to capture high impedance fault conditions within HFRA. DCD has been installed across 87 percent of the HFRA. These installations have reduced high impedance fault type ignitions but there remains a gap on extreme low amperage fault conditions that DCD cannot detect.	Enhance the sensitive ground fault pick-ups to allow for detection of high impedance fault conditions not detectable by the existing DCD algorithm. Also, continue the reprogramming of SGF trip floor settings criteria to increase detection of faults to 5-amp fault conditions within five seconds.	2024-2028	ACI PG&E-23-14
2022	Wildfire and resiliency work	<u>Source</u>: collaboration with local wildfire mitigation planning	Our wildfire and climate resiliency work is not connected to the work of communities and agencies.	Wildfire & Climate Resiliency Chief is currently developing a Wildfire Resilience Corridors pilot with a community within our AOC. The pilot's goal is to co-develop wildfire mitigation programs and projects with pilot communities that will mutually benefit both community assets and utility infrastructure.	2025 to 2028	N/A

13.2 Working Group Meetings

The electrical corporation must identify any Energy Safety-required working group meetings attended or planning to attend in the WMP submission year and provide any lessons learned that applied to its WMPs. The electrical corporation must include interactions and collaborations related to the electrical corporation's WMP submission such as identifying new technology, industry best practices, and shared lessons learned from the WMP process.

PG&E participates in Energy Safety-required working group meetings to collaborate with the other electrical corporations and share information concerning new technology, industry best practices, and shared lessons learned.

There are three joint ACIs that PG&E recognizes as Energy Safety-required working group meetings with other utilities. These working groups are discussed in Table PG&E-13.2-1 below.

TABLE PG&E-13.2-1:
WORKING GROUPS AND LESSONS LEARNED

Energy Safety-Required Meetings by Area for Continuous Improvement	Interactions Attended or Planned	Lessons Learned
ACI PG&E 25U-02: Cross-Utility Collaboration on Best Practices for Inclusion of Climate Change Forecasts in Consequence Modeling, Inclusion of Community Vulnerability in Consequence Modeling, and Utility Vegetation Management for Wildfire Safety	PacifiCorp, PG&E, SCE, and SDG&E participate in monthly meetings in addition to the engagements referenced in Appendix D for ACI PG&E 25U-02. The above referenced meetings are scheduled to continue through 2025.	The utilities improved our understanding of the maturity of remote sensing technologies and learned how to utilize such technologies to supplement current practices. We also learned from each other's demonstrations and use cases for remote sensing technologies such as satellite and LiDAR-based identification.
ACI PG&E-25U-03: Continuation of Grid Hardening Joint Studies	PacifiCorp, PG&E, SCE, and SDG&E participate in quarterly meetings to provide a platform to benchmark and share undergrounding best practices. PG&E, SCE, and SDG&E participate in bi-monthly meetings to discuss mitigation effectiveness studies. Liberty, PacifiCorp, PG&E, Nevada Energy, SCE, and SDG&E participate in monthly meetings to discuss System Protection and Device Settings. These sessions also include discussions on Covered Conductors. These meetings are scheduled through 2025.	See Appendix D for ACI PG&E-25U-03, for applicable lessons learned.
ACI PG&E23B-22: Continuation of Effectiveness of Enhanced Clearance Joint Study	PG&E, SCE, and SDG&E participate in bi-monthly meetings to conduct ongoing discussions regarding enhanced VM mitigation efforts. The above referenced meeting is scheduled to continue through 2025.	See Appendix D for ACI PG&E23B-22 for applicable lessons learned.

13.3 Discontinued Activities

The electrical corporation must provide all activities from previous WMP submissions that it is no longer implementing ("Discontinued Activities"),[252] *the rationale for discontinuation, the applicable lessons learned, and a list of the new or existing activities that mitigate risk in place of the discontinued activity ("Replacement Activities"), including cross-references to the page numbers within the WMP where each replacement activity is discussed.*

Table 13-2 below provides a list of activities (with and without targets) from previous WMP submissions that PG&E has discontinued, the rationale for the discontinuation, any applicable lessons learned from those activities, and the new or existing activities that mitigate risk in place of the discontinued activity. Although these activities are listed as discontinued (i.e., no longer tracked as WMP targets), some may continue as ongoing mitigation efforts as warranted.

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[252] *Discontinued activities do not include activities that the electrical corporation has completed. An activity that has been completed is not a discontinued activity.*

TABLE 13-2:
LESSONS LEARNED FROM DISCONTINUED ACTIVITIES

Discontinued Activity (Tracking ID)	Rationale for Discontinuation	Lessons Learned	Replacement Activities (Include Page Number Where Discussed)
Transmission – Ground Detailed Inspection Program (AI-02) and Transmission – Aerial Detail Inspection (AI-04)	Programs are being combined based on visual aspects of both programs. The program is now known as Transmission – Detailed Inspection Program.	Combining Ground and Aerial programs into one target allows for flexibility to address wildfire risk by method choice to best suit location and structure type.	Transmission – Detailed Inspection Program Section 8.3.1; p. 232
Transmission Climbing Detailed Inspection Program (AI-05)	This program will still continue, but not under a WMP target.	Climbing program focuses on 500 kV steel structure integrity which is not a common source of ignition.	Transmission – Detailed Climbing Inspection Program Section 8.3.2; p. 234
Substation Supplemental Inspections (removal of ground and infrared inspections and continuing aerial drone inspections as a part of routine inspections) (Formerly AI-08, AI-09, and AI-10)	The WMP substation supplemental inspection program was originally developed to focus on ignition risks independent from existing routine substation inspections. A comparative analysis of supplemental and routine inspections was completed in 2023 and 2024. This analysis confirmed redundancy and equal effectiveness of two of the three methods—ground and infrared inspection. Furthermore, substation routine ground inspections are performed more frequently, monthly or bi-monthly, in comparison to the annual supplemental inspection. PG&E proposes to streamline substation inspections by removing duplicative ground	PG&E originally planned supplemental inspection targets by requiring three separate methods for each single supplemental inspection: ground, infrared, and aerial. The 2026-2028 WMP will continue with drone-based aerial inspections as a part of the ongoing routine inspection process but will remove the duplicative ground and infrared supplemental inspection methods. This proposed change is expected to yield equivalent ignition risk detectability while streamlining the inspections programs to be more efficient.	Substation Drone Inspection Program Section 8.3.15; p. 258

TABLE 13-2:
LESSONS LEARNED FROM DISCONTINUED ACTIVITIES
(CONTINUED)

Discontinued Activity (Tracking ID)	Rationale for Discontinuation	Lessons Learned	Replacement Activities (Include Page Number Where Discussed)
	and infrared inspections, while retaining drone-based aerial inspections as a part of the routine inspections process. The drone-based aerial inspection provides unique risk detection perspectives not captured from the ground and infrared methods. The routine substation inspection program will continue to provide ground and infrared inspections to substations pursuant to GO 174. Power Generation Switchyards are regulated either by GO 167, or Federal Energy Regulatory Commission (FERC) in situations where operations are under a FERC license. These regulatory commitments focus on maintenance and operations requirements, and do not identify an inspection requirement. Power Generation performs routine inspections of switchyards in alignment with substation routine inspection program.		
Filling Asset Inventory Data Gaps (AI-11)	AI-11 has been replaced by ES-02.	This activity will continue under ES-02, which is described in Section 12.1.1.	Evaluate and create new method(s) to improve the accuracy of asset inventory data (ES-02) Section 12.1.1; p. 544
Community Engagement - Meetings (CO-01)	This activity is being reported on externally in other forums.	PG&E will incorporate this activity into Section 11.4.3.	Section 11.4.3; p. 520
Community Engagement - Surveys (CO-02)	This activity is being reported on externally in other forums.	PG&E will incorporate this activity into Section 11.4.3.	Section 11.4.3; p. 520

TABLE 13-2:
LESSONS LEARNED FROM DISCONTINUED ACTIVITIES
(CONTINUED)

Discontinued Activity (Tracking ID)	Rationale for Discontinuation	Lessons Learned	Replacement Activities (Include Page Number Where Discussed)
Complete PSPS and Wildfire Tabletop and Functional Exercises (EP-01).	This activity is being reported on externally in other forums.	This Emergency Preparedness program addresses hazards beyond wildfires and we have worked to ensure wildfire related activities are included within these processes.	N/A
Maintain all hazards planning and preparedness program in 2023-2025 (EP-02)	This activity is being reported on externally in other forums.	This Emergency Preparedness program addresses hazards beyond wildfires and we have worked to ensure wildfire related activities are included within these processes.	N/A
Expand all hazards planning to include additional threats and scenarios in 2023-2025 (EP-04)	This activity is being reported on externally in other forums.	This Emergency Preparedness program addresses hazards beyond wildfires and we have worked to ensure wildfire related activities are included within these processes.	N/A
Annually review of CERP and the two wildfire related annexes (EP-06)	This activity is being reported on externally in other forums.	This Emergency Preparedness program addresses hazards beyond wildfires and we have worked to ensure wildfire related activities are included within these processes.	N/A
Threats and Hazards Identification and Risk Assessment (THIRA) updates executive briefings (EP-08)	This activity is being reported on externally in other forums.	The THIRA is an all-hazard identification beyond just wildfires and we have worked to ensure wildfire related activities are included in these processes.	N/A
System Hardening – Distribution (GH-01) [(a)]	Revised Overhead Hardening Distribution Target (GH-12) and new Line Removal Enabled by Remote Grid Target (GH-14).	This activity has been incorporated into GH-12, which is described in Section 8.2.1. and GH-14, described in Section 8.2.7.1.	Covered Conductor Installation Section 8.2.1; p. 184 Remote Grids Section 8.2.7.1, p. 211

TABLE 13-2:
LESSONS LEARNED FROM DISCONTINUED ACTIVITIES
(CONTINUED)

Discontinued Activity (Tracking ID)	Rationale for Discontinuation	Lessons Learned	Replacement Activities (Include Page Number Where Discussed)
Reduce PSPS impacts to customer events (PS-07)	PG&E will continue this work, but not under a WMP target.	Significant progress made during the 2023-2025 WMP cycle to reduce PSPS impacts to customers.	N/A
Artificial Intelligence in Wildfire Cameras (SA-01)	SA-01 is continued under SA-08.	PG&E will incorporate this activity under SA-08 described in Section 10.4.1.	Existing Ignition Detection Sensors and Systems Section 10.4.1; p. 455
LiDAR Data Collection – Transmission (VM-01)	We will continue to improve remote sensing with LiDAR and Satellite technologies.	• LiDAR tree analytics capture risk in the system. • Inspectors use LiDAR analytics for all spans in Transmission. • We are evaluating the use of satellite or spaceborne data for Transmission.	Satellite technology evaluation in progress Section 9.2; p. 363
Focused Tree Inspections (FTI) (VM-03)	Component(s) of the initiative will be incorporated into the Distribution Routine Patrol Program.	PG&E is still in the process of evaluating which component(s) of the FTI scope may be incorporated into the Distribution Routine Patrol program. This analysis will be based on findings from efficacy studies planned to be performed in 2025.	Distribution Routine Patrol Section 9.2.1; p. 365
Tree Removal Inventory (TRI) (VM-04)[(b)]	Revised to Mitigation of Legacy Tree Removal Inventory (TRI) (VM-26).	In the proposed consolidated program structure, the process of what was the legacy TRI Program will occur during the distribution routine programs. See VM-26.	Distribution Routine Patrol Section 9.2.1; p. 410
Evaluate emerging technologies (VM-12)	This work will continue, but not under WMP target.	VM is evaluating emerging technologies as it pertains to individual programs. For example, VM distribution inspections is reviewing remote sensing technology for potential incorporation into this program's process.	Distribution Routine Patrol Section 9.2.1; p. 410

TABLE 13-2:
LESSONS LEARNED FROM DISCONTINUED ACTIVITIES
(CONTINUED)

Discontinued Activity (Tracking ID)	Rationale for Discontinuation	Lessons Learned	Replacement Activities (Include Page Number Where Discussed)
Vegetation Management for Operational Mitigations (VMOM) (VM-18)	Component(s) of the initiative will be incorporated into Activities Based on Weather Conditions	PG&E will incorporate VMOM into activities described in Section 9.9.1.	Activities Based on Weather Conditions Section 9.9.1; p. 410
Smart Tape (N/A)	PG&E funded a lab-only proof of concept in 2022-2023 using the EPSS Emergent Technology expense budget to evaluate the feasibility of using "smart tape" technology for rapid fault location on EPSS-enabled lines. The proof of concept was structured in three phases. PG&E decided to conclude the project at the end of Phase II, due to the following findings: 1) The vendor had not demonstrated sufficiently rapid product development progress in line with PG&E's needs. 2) The proposed equipment design had moved away from initial "smart tape" concept to a larger, bulkier design that no longer held unique value proposition compared to other market-available sensors 3) The proposed design was not compatible with PG&E's desire for cost-effectiveness at scale.	This effort validated the use of a phased approach with clear exit clauses when evaluating solutions with low technology readiness levels. This type of phased approach allows PG&E to engage with technology vendors iterating on early prototypes while managing the inherent risks of early-stage technology. PG&E's contract structure and overall approach with the "smart tape" vendor has provided a model for other engagements involving low technology readiness levels.	Real-time monitoring for wildfire risk reduction, including, but not limited to Gridscope. For more information on Gridscope, see Section 8.7.1.3.2; p. 344

(a) See 2026-2028 WMP Revision Notice Response R0, Critical Issue RN-PGE-26-04 for additional information.
(b) See 2026-2028 WMP Revision Notice Response R0, Critical Issue RN-PGE-26-09 for additional information.

We have completed the following activities (with or without targets) listed in Table PG&E-13.3-1 based on known populations. Although these activities are listed as completed (i.e., no longer tracked as WMP targets), some may continue as ongoing mitigation efforts as warranted.

TABLE PG&E-13.3-1:
COMPLETED WMP ACTIVITIES

Activity	2023-2025 WMP Section Number	2023-2025 WMP Activity Tracking ID	Completion Year
Installation of System Automation Equipment – Distribution Protective Devices	8.1.2.8.1	GH-07	2023
Installation of System Automation Equipment – Installation of Devices to Eliminate High Impedance Back feed Conditions	8.1.2.10.2	N/A	2024
Line Removal (in the HFTD) – Transmission	8.1.2.9.1	N/A	2024
Motor Switch Operator Switch Replacement	8.1.2.10.3	GH-09	2024
Non-Exempt Surge Arrester Replacement	8.1.2.10.4	GH-08	2024
Replace Non-Exempt Expulsion Fuses	8.1.2.10.5	GH-10	2025
Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Transmission	8.1.2.11.1	N/A	2023
Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Distribution	8.1.2.11.2	N/A	2023
Other Grid Topology Improvements to Mitigate or Reduce PSPS Events – Substation	8.1.2.11.3	N/A	2022
The Calistoga Temporary Microgrid (There are currently no plans to deactivate the remaining 12 active temporary microgrids)	8.1.2.7.2	N/A	2025
Retainment of Inspectors and Internal Workforce Development	8.1.9.1	AI-01	2025
Develop Distribution Aerial Inspections Program	8.1.3.2.7	AI-03	2023
Evaluate Covered Conductor Effectiveness	8.1.2.1	GH-02	2025
Evaluate and Implement Covered Conductor Effectiveness Impact on Inspections and Maintenance Standard	8.1.2.1	GH-03	2023
System Hardening - Transmission	8.1.2.5.1	GH-05	2024
HFTD/HFRA Open Tag Reduction – Transmission	8.1.7.1	GM-02	2024
EPSS – Down Conductor Detection	8.1.2.10.1	GM-06	2024
Eliminate HTFD/HFRA Distribution Backlog	8.1.7.2	GM-08	2023
Evaluate enhancements for the PSPS Transmission guidance	9.2.1	PS-01	2025
Evaluate incorporation of approved IPW enhancements into the PSPS Distribution guidance	9.2.1	PS-02	2025

TABLE PG&E-13.3-1:
COMPLETED WMP ACTIVITIES
(CONTINUED)

Activity	2023-2025 WMP Section Number	2023-2025 WMP Activity Tracking ID	Completion Year
Pilot using drones for PSPS restoration	9.1.2	PS-11	2024
Evaluate the transition of the Portable Battery Program to permanent battery solutions	8.5.3	PS-05	2025
Provide portable batteries to PG&E customers	8.5.3	PS-06	2025
Evaluate emerging technologies to reduce PSPS customer impact	9.1.2	PS-08	2025
Reduce PSPS impacts via Undergrounding	9.1.2	PS-09	2025
EFD and DFA Reporting	8.3.3.1	SA-03	2025
FPI and IPW Modeling - Revision Evaluation	8.3.6.3	SA-04	2025
Evaluate FPI and IPW Modeling enhancements in 2023-2025	8.3.6.3	SA-05	2025
Monitor and evaluate the Cameras AI system’s performance	8.3.2.3	SA-07	2025
EFD and DFA Reporting	8.3.3.1	SA-09	2025
Evaluate FPI and IPW Modeling enhancements in 2026-2032	8.3.6.3	SA-06	2025
Constraint Resolution Procedural Guideline	8.2.6	VM-09	2025
One VM Application Record Keeping Enhancement (Routine, Second Patrol)	8.2.4	VM-19	2024
Record Keeping Enhancement (VMOM, TRI)	8.2.4	VM-20	2024
FTI Program Record Keeping Enhancement	8.2.2.2.5	VM-21	2024
Inspection in HFTD and HFRA supporting key vegetation management initiatives	8.2.2	VM-10	2024
Enhance and refine Focus Tree Inspection – AOC	8.2.2.2.5	VM-11	2024

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

APPENDICES A, B, C, E, AND F ARE AVAILABLE IN

2026-2028 WMP VOLUME 2

PACIFIC GAS AND ELECTRIC COMPANY

2026-2028 WILDFIRE MITIGATION PLAN

APPENDIX D

AREAS FOR CONTINUED IMPROVEMENT

Appendix D – Areas for Continued Improvement

ACI PG&E-25U-01 – Outage to Ignition Risk Analysis

Description:

PG&E does not include analysis of the likelihood of ignition based on various outage types when evaluating ignition risk as part of its modeling improvements.

Required Progress:

In its 2026-2028 Base WMP, PG&E must provide an update on how it is working to incorporate evaluation of ignition likelihood based on various outage types when modeling ignition risk and analyzing mitigation effectiveness as a result. This must include analysis of individual outage-drivers and ignition-drivers, propagation likelihood from outage-to-ignition, and inclusion of ignition sources without associated outages.

Section and Page Number of Any Improvements:

Section 5.2, page 50.

PG&E Response:

The WDRM v4 probability of ignition model does distinguish by outage type.

Specifically, the WDRM v4 includes the introduction of event cause and equipment type interaction terms to the Probability of Ignition given Outage (p(i|o)) model to improve performance for causal pathways that share underlying characteristics for weather and fuels. To achieve this, an expanded set of Pf/Outage causal models has been developed. The p(i|o) model correlates to failure/outage rates, weather conditions, fuel conditions and availability, and other location-specific attributes. However, the correlation between fuel and weather conditions and ignition outcomes also depends on the nature of the underlying events. Specifically, some events, like transformer failures predominantly result in pole fires that are not influenced by fuels on the ground, while others, like insulator tracking faults, require moisture and condensation for an event to occur. The introduction of event cause and equipment type labels for events allowed the use of interaction terms that produce separate weather and fuels correlation terms for distinct groups of events that share the same characteristics. An important purpose for the p(i|o) model is to support tradeoffs between mitigation strategies.

Table ACI-PG&E-25U-01-1 below outlines the 12 individual p(i|o) sub-models and their correlation to the 22 probability of outage models. More details on the development and technical basis of these sub models are available in the DEPM v4 Documentation,[253] Section 3.6 Probability of Ignition Model, pp. 81-86.

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[253] The supporting document is available at: PG&E's Community Wildfire Safety Program.

TABLE ACI-PG&E-25U-01-1:
CORRELATION BETWEEN SUB MODELS AND OUTAGE MODELS

Model Group	Member Models	Outages (count)	Ignitions (count)	Ignitions per Outage
1	Vegetation – Branch, Vegetation – Trunk	12,022	751	6.2%
2	Support Structure – Electrical	4,033	713	17.7%
3	Animal – Squirrel, Third-Party – Balloon, Third-Party – Vehicle, Third-Party – Other	18,040	613	3.4%
4	Primary Conductor – Wire Down	5,317	515	9.7%
5	DPD, Capacitor Bank, Fuse, Switch, Voltage Regulator	6,544	498	7.6%
6	Animal – Bird, Animal – Other, Primary Conductor – Line Slap, Transformer – Leaking	8,411	388	4.6%
7	Transformer – Equipment	14,297	269	1.9%
8	Secondary Conductor	3,318	220	6.6%
9	Vegetation – Other	1,931	209	10.8%
10	Other Equipment	54,053	188	0.3%
11	Support Structure – Equipment	4,314	187	4.3%
12	Primary Conductor – Other	1,961	179	9.1%

The p(i|o) model produces separate weather and fuels correlation terms for distinct groups of events that share the same characteristics.

An important purpose for the p(i|o) model is to support tradeoffs between mitigation strategies, including EPSS. Therefore, the v4 p(i|o) model needed to be calibrated to predict the number of ignitions that would be expected without EPSS. Section 3.3 explains how the ignitions event training data was modified to account for EPSS impacts.

ACI PG&E-23B-03 – Incorporation of Extreme Weather Scenarios in Planning Models

Description:

PG&E currently relies on wind conditions data collected over the past 30 years that does not consider rare but foreseeable and significant risks. PG&E does not directly evaluate the risk of extreme wind events in its service territory to prioritize its wildfire mitigations using the WTRM Planning model.

Required Progress:

In its 2026-2028 Base WMP, PG&E must report on its progress developing statistical estimates of potential wind events over at least the maximum asset life for its system. PG&E must evaluate results from incorporating these into WTRM-Planning when developing its mitigation initiative portfolio or explain why the approach would not serve as an improvement to its mitigation strategy.

Section and Page Number of Any Improvements:

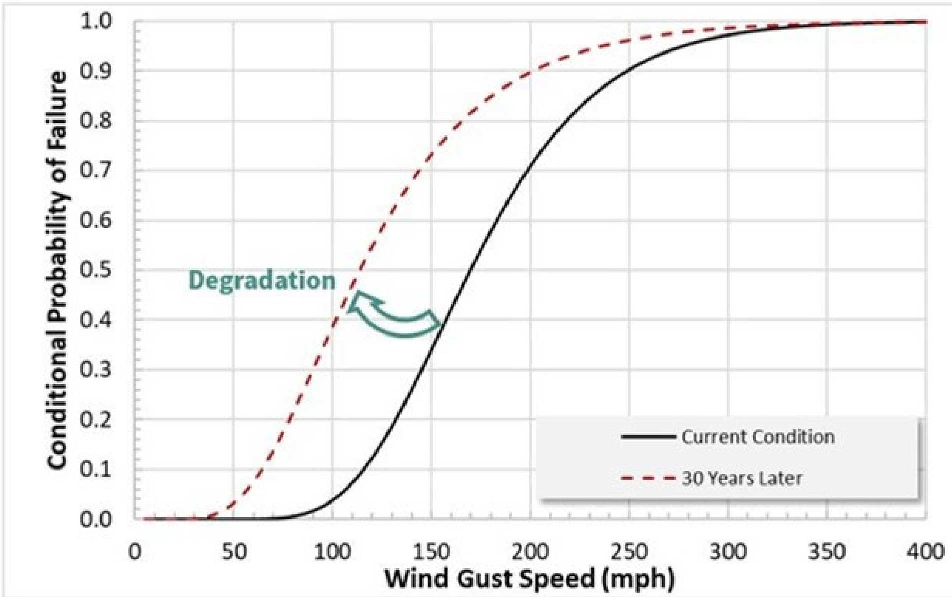
Section 5.3, page 83.

PG&E Response:

PG&E confirms that it has developed statistical estimates of potential wind events over the maximum asset life for its system. The WTRM integrates the impact of wind events throughout the lifecycle of the assets, as depicted in Figure PG&E-6.2-4 of PG&E's 2023-2025 WMP, which outlines the Threat-Hazard framework of WTRM.[254] The accompanying chart, Figure ACI-PG&E-23B-03-1, from the illustration demonstrates the incorporation of wind speeds into the calculations. As the asset age increases, the fragility curves adjust, leading to an increased conditional Pf at any specific wind speed. This fragility curve, in conjunction with the exceedance curves of the wind hazard, is utilized to calculate the annual Pf within the WTRM. Thus, PG&E can confirm that it has evaluated the results from incorporating these wind events into WTRM planning as part of its mitigation portfolio.

[254] PG&E 2023-2025 WMP R7 at 152.

FIGURE ACI-PG&E-23B-03-1:
WTRM FRAGILITY CURVE



ACI PG&E-25U-02 – Cross-Utility Collaboration on Best Practices for Inclusion of Climate Change Forecasts in Consequence Modeling, Inclusion of Community Vulnerability in Consequence Modeling, and Utility Vegetation Management for Wildfire Safety

Description:

San Diego Gas & Electric Company (SDG&E), PG&E, and Southern California Edison Company (SCE) have participated in past Energy Safety-sponsored scoping meetings on these topics and have begun collaborating on other WMP-related topics. However, they have not made sufficient efforts to include the other IOU (Bear Valley, Liberty Utilities, and PacifiCorp).

Required Progress:

In its 2026-2028 Base WMP, PG&E must continue its collaboration efforts and demonstrate that it has made efforts to include Bear Valley, Liberty Utilities, and PacifiCorp in these efforts, where appropriate and relevant to each IOU's interests.

PG&E must also continue to participate in all Energy Safety-organized activities related to best practices for:

- *Inclusion of climate change forecasts in consequence modeling;*
- *Inclusion of community vulnerability in consequence modeling; and*
- *Utility VM for wildfire safety.*

Section and Page Number of Any Improvements:

Section 13.2, which includes Lessons Learned, page 559.

PG&E Response:

Collaboration With Bear Valley, Liberty Utilities, and PacifiCorp

PG&E collaborates with other utilities, including Bear Valley, Liberty Utilities, PacifiCorp and Hawaiian Electric through monthly meetings focusing on Energy Safety activities and other WMP-related topics such as:

- Inspection programs;
- VM programs;
- Quality Control programs;
- Internal and Contract Resources;
- Remote Sensing Technologies; and
- Optimization of the off-cycle HFTD inspections.

The utilities also collaborate by participating in various industry related events throughout the year to share best practices and further knowledge on these topics.

Inclusion of Climate Change Forecasts in Consequence Modeling

PG&E will continue to participate in all Energy Safety-organized activities related to best practices for inclusion of climate change forecasts in consequence modeling.

Inclusion of Community Vulnerability in Consequence Modeling

PG&E will continue to participate in all Energy Safety-organized activities related to best practices for inclusion of community vulnerability in consequence modeling.

Utility Vegetation Management for Wildfire Safety

PG&E will continue to participate in all Energy Safety-organized activities related to best practices for utility VM for wildfire safety.

ACI PG&E-25U-03 – Continuation of Grid Hardening Joint Studies

Description:

The IOUs have jointly made progress addressing the continued Joint IOU Covered Conductor Working Group area for continued improvement (ACI) (PG&E-23-06). Energy Safety expects the IOUs to continue these efforts and meet the requirements of this ongoing ACI.

Required Progress:

In its 2026-2028 Base WMP, PG&E must continue to collaborate with the other IOUs to evaluate various aspects of grid hardening and provide an updated Joint IOU Grid Hardening Working Group Report. This report must include continued analysis for the following:

- *The IOUs' continued joint evaluation of the effectiveness of covered conductor for reducing ignition risk and PSPS risk, and outage risk associated with PEDS. This evaluation must include analysis of risk reduction observed in-field as well as research on covered conductor degradation over time and its associated lifetime risk mitigation effectiveness.*

- *The IOUs' joint evaluation of the effectiveness of undergrounding for reducing ignition risk, PSPS risk, and outage risk associated with PEDS. This evaluation must account for any remaining risk from secondary or service lines and analysis of in-field observations from potential failure points of underground equipment.*

- *The IOUs' joint evaluation of lessons learned on undergrounding applications. These lessons learned must include use of resources (including labor and materials) to accommodate undergrounding programs, any new technologies being applied to undergrounding, and cost and associated cost effectiveness efforts for deployment.*

- *The IOUs' joint evaluation of various approaches to implementation of PEDS. This evaluation must include an analysis of the effectiveness of various settings, lessons learned on how to minimize reliability impacts and safety impacts (including use of DCD and partial voltage detection devices), variations on settings used by IOUs including thresholds of enablement, and equipment types in which such settings are being adjusted.*

- *The IOUs' continued efforts to evaluate new technologies being researched, piloted, and deployed by IOUs. These efforts must include, but not be limited to: Rapid Earth Fault Current Limiter, EFD, DFA, falling conductor protection, use of SmartMeter data, open phase detection, remote grids, and microgrids.*

The IOUs' joint evaluation of the effectiveness of mitigations in combination with one another, including, but not limited to OH system hardening, maintenance and replacement, and situational awareness mitigations. This must also include analysis of in-field observed effectiveness, interim risk exposure during implementation, and how those impact effectiveness for ignition risk, PSPS risk, and outage risk associated with PEDS.

- *Additionally, PG&E must report on all lessons learned SCE [sic] has applied or expects to apply to its WMP, including a list of applicable changes and a timeline for expected implementation as applicable.*

Section and Page Number of Any Improvements:

Section 13.2, page 559. Also see Topic #6 in the Continuation of Grid Hardening Joint Studies.

PG&E Response:

In response to this ACI, collaboration with the other IOUs continued to evaluate various aspects of grid hardening. The resulting report, Continuation of Grid Hardening Joint Studies, is available at PG&E's Community Wildfire Safety Program.

ACI PG&E-25U-04 – Decrease in Detailed Ground Distribution Inspections

Description:

In its 2025 WMP Update, PG&E provided analysis supporting its established inspection frequencies for "high" and "medium" consequence plat maps. While this analysis supports its decision-making process, it does not demonstrate that the established frequencies mitigate risk more efficiently than alternatives.

Required Progress:

In its 2026-2028 Base WMP, PG&E must provide a cost benefit analysis and CBR for the following scenarios:

- *Extreme and severe consequence plat maps inspected annually, high inspected every two years, low and medium inspected every three years.*

- *Extreme, severe, and high consequence plat maps inspected annually, medium and low inspected every three years.*

- *Extreme, severe, and high consequence plat maps inspected annually, medium inspected every two years, and low inspected every three years.*

- *Extreme and severe consequence plat maps inspected annually, high and medium inspected every two years, low inspected every three years.*

- *Changing the severe consequence percent rank from less than or equal to 99 percent and greater than 98 percent to less than or equal to 99 percent and greater than 95 percent and inspecting extreme and severe consequence plat maps annually, high every two years, medium and low every three years.*

The cost benefit analysis and CBR must only consider the risk impact of the distribution detailed inspection frequencies outlined above and must not account for reductions to other inspection or maintenance programs.

Section and Page Number of Any Improvements:

Section 8.1.2, page 177.

PG&E Response:

PG&E calculated the requested scenarios and compared them to the scenario being proposed in its 2026-2028 WMP, which proposes detailed inspections on three-year cycles for all structures and a new aerial scan inspection on extreme, severe and high consequence and risk locations. Table ACI-PG&E-25U-04-1 is provided below. The benefit is calculated as eyes on risk for both detailed and aerial scan inspections, while the cost is the estimated unit cost of the inspection.

TABLE ACI-PG&E-25U-04-1:
INSPECTION SCENARIO SUMMARY

Scenarios	Scenario Description	Detailed Inspections	Scan Inspections	Eyes-on-Risk	Total Cost	CBR (x10^-8)
WMP Proposed	All structures receive detailed inspections every three years with Extreme/Severe/High structures also receiving scans in between years, such as the overall frequencies are extreme and severe inspected every year (either by detailed or scan), high inspected every two years (either by detailed or scan), low and medium inspected every three years (by detailed).	218,395	37,042	57.0%	$32.8 million	1.737
1	Extreme and severe consequence plat maps inspected annually, high inspected every two years, low and medium inspected every three years.	238,310	–	49.7%	$33.4 million	1.489
2	Extreme, severe, and high consequence plat maps inspected annually, medium and low inspected every three years.	278,848	–	66.0%	$39.0 million	1.691
3	Extreme, severe, and high consequence plat maps inspected annually, medium inspected every two years, and low inspected every three years.	326,053	–	72.2%	$45.6 million	1.582
4	Extreme and severe consequence plat maps inspected annually, high and medium inspected every two years, low inspected every three years.	285,516	–	55.9%	$40.0 million	1.398
5	Changing the severe consequence percent rank from less than or equal to 99 percent and greater than 98 percent to less than or equal to 99 percent and greater than 95 percent and inspecting extreme and severe consequence plat maps annually, high every two years, medium and low every three years.	251,556	–	57.1%	$35.2 million	1.622

PG&E's proposed 2026-2028 scenario is the most risk efficient, achieving a CBR of 1.737 x 10^-8. This scenario is the most risk efficient scenario because it adds additional eyes-on-risk via scan inspections on our highest risk and consequence structures in years between detailed inspections. When detailed inspections and scan inspections are considered together, extreme and severe assets receive eyes-on-risk every year and high assets receive eyes-on-risk two out of three years, an improvement over eyes-on-risk every other year on this category as implemented for 2024 and 2025. Executing scan inspections allows for the identification of the highest risk conditions at a lower cost allowing for more frequent inspections in high risk or consequence locations.

The second most risk-efficient scenario was scenario two (CBR: 1.691 x 10^-8), in which extreme, severe and high consequence structures are inspected annually via detailed inspection. Scenario 4 was the least risk-efficient because although it includes the more structures each year than most other scenarios, the average risk per structure is much lower, and only half of high consequence assets are inspected each year.

Methodology

For this analysis, PG&E assumed that all detailed inspections would be carried out by aerial at a cost of $160 and all scan inspections would cost $60.

For all risk calculations, PG&E utilized WDRM v4. PG&E shifted from consequence driving inspection frequency to consequence OR risk driving inspection frequency, to additionally capture areas of high risk. Additionally, the low and medium consequence grouping percentiles shifted to align to VM consequence groupings. Note that this change does not have an impact to inspections completed. Table ACI-PG&E-25U-04-2 is provided below comparing risk model percentage groupings.

See Revision Notice Response to Critical Issue RN-PGE-26-06 for more information.

TABLE ACI-PG&E-25U-04-2:
COMPARISON OF RISK MODELS PERCENTILE GROUPINGS USED IN DISTRIBUTION INSPECTION PLANNING

	Risk Model	Factor	Extreme	Severe	High	Medium	Low
2023-2025 WMP	WDRM v3	Consequence	0-1%	1-2%	1-10%	10-20%	20-100%
2026-2028 WMP Proposal	WDRM v4	Risk OR	0-1%	1-2%	1-10%	10-20%	20-100%
		Consequence	0-1%	1-2%	1-10%	10-40%	40-100%

ACI PG&E-25U-05 – Transformer Predictive Maintenance

Description:

In its 2025 WMP Update, PG&E stated it will conduct tests to evaluate the accuracy of the IONA model and operationalize the model if it can achieve beneficial risk-spend efficiency. PG&E does not commit to reporting on test results or calculated risk-spend efficiencies.

Required Progress:

In its 2026-2028 Base WMP, PG&E must provide:

- *All testing results and documentation, reports, and/or whitepapers relevant to the IONA project.*
- *All risk-spend efficiency calculations relevant to the IONA project.*

Section and Page Number of Any Improvements:

Section 8.4.11, page 289.

PG&E Response:

Upon the completion of EPIC 3.20, the transformer failure prediction model transitioned to the IONA project. IONA is a machine learning model that detects voltage anomalies using SmartMeter voltage and loading data along with weather data, transformer age, and geographical information to predict transformer failures. The model assigns a Pf that updates weekly. PG&E's Asset Health & Performance Center has been running the IONA model consistently since January 2024, conducting engineering analysis on failure predictions generated by the model. Once the voltage/load anomalies are confirmed, a potential root cause is assigned by the reviewer and sent on for further investigation.

In 2024, 282 investigations were completed using the IONA model, which resulted in 44 transformers (9 in HFTD Tier 2 and 3 areas) being replaced prior to failure (Risk Reduction: 1.19283 per WDRM v4 model). There were 104 cases (23 in HFTD Tier 2 and 3 areas) where investigations revealed other system risks (e.g., loose/broken neutral, broken jumpers, wiring issues, circuit reactive component issues, failed fuses, energy theft) that were remediated.

101 of the cases shortlisted for investigation by the model were non-actionable—these included circuit outages, SmartMeter (non-billing) data issues etc.

Table ACI-PG&E-25U-05-1 provides the IONA Program results summary. Table ACI-PG&E-25U-05-2 provides the risk reduction calculation using the WDRM v4 model.

TABLE ACI-PG&E-25U-05-1:
IONA PROGRAM 2024 RESULTS SUMMARY

Category	Investigation Count			Transformer Count	Comments
	Non-HFTD	HFTD2/3	Total		
Successful Intervention – Replaced Transformer	29	9	38	44	Incipient transformer failures – remediation initiated through IONA[a]
Successful Prediction – Replaced Transformer	14	4	18	18	Transformer Failures – remediation initiated independent of IONA
Sub-total – Transformer Remediation	43	13	56	62	
Successful Intervention – Non-TX Remediation	81	23	104	–	Non-transformer risks – remediation initiated through IONA
Successful Prediction – Non-TX Remediation	11	4	15	–	Non-transformer risks – remediation initiated independent of IONA
Sub-total – Non Transformer Remediation	92	27	119	–	
Non-Risk Issue	80	21	101	–	Outages, SmartMeter data issues etc.
False Positive Prediction	5	1	6	–	False positive prediction by model
Total	220	62	282	–	

(a) Transformer count higher than investigation count since some locations involved transformer banks

Notes:

- <u>Successful Intervention</u>: IONA predicted issue, remediated through IONA workflow.
- <u>Successful Prediction</u>: IONA predicted issue, remediation was initiated independent of IONA workflow.

TABLE ACI-PG&E-25U-05-2:
RISK REDUCTION CALCULATION PER WDRM v4

Risk Reduction Category	Risk Reduction Calculated Using WDRM v4
Transformer Unit Replacements (44 Transformers)	1.192449759
Additional Equipment Replaced (Pole, crossarm)	0.000380047
Total Risk Reduction	1.192829806

The IONA Program provides eyes on risk, then risk remediation is accomplished through existing maintenance programs and funding. Hence the IONA Program by itself does not have a Risk Spend Efficiency calculation.

PG&E plans to re-train the IONA model based on results from desktop reviews and field investigation findings conducted in 2024 to improve model accuracy. The IONA model has shown the capability to identify system risks over and above transformer issues, which is beneficial to PG&E ignition risk reduction efforts.

The detailed IONA Program results are available at the following link: PG&E's Community Wildfire Safety Program.

ACI PG&E-25U-06 – Evaluation and Reporting of Safety Impacts Relating to EPSS

Description:

In its 2025 WMP Update, PG&E stated that it plans to continue EPSS enablement in R2 and R1 conditions. These lower thresholds present higher outage risk without as high of an associated ignition risk, which requires additional analysis and oversight to manage moving forward.

Required Progress:

In its 2026-2028 WMP, PG&E must provide its latest 2024 analysis pertaining to EPSS outages, which should include the following for each CPZ in which EPSS has been enabled:

- *Number of outages that have occurred;*
- *Whether or not the CPZ is in the HFTD;*
- *Cumulative number of customers impacted by those outages;*
- *Cumulative CMI during those outages;*
- *Cumulative outage time in minutes;*
- *Number of circuit-mile-days in which EPSS criteria was met, including conditions used in order for criteria to be met;*
- *Percentage of time in which EPSS was enabled at each FPI threshold (R2, R3, etc.);*
- *Cumulative number of customers impacted by outages at each FPI threshold.;*
- *Cumulative CMI at each FPI threshold;*
- *Cumulative outage time at each FPI threshold;*
- *Any associated conclusions or changes to threshold enablement as a result of analysis on the above; and*
- *Any continued or additional measures PG&E is taking to minimize customer impact based on EPSS enablement.*

Section and Page Number of Any Improvements:

Section 8.7.1.1, page 332.

PG&E Response:

The following details serve as a narrative companion to the EPSS Reliability Study, as well as ACI PG&E-25U-06, to provide information that is not included in the spreadsheet in which most data is provided. The attached EPSS Reliability Study Analysis,[255] using 2024 outage data, contains the information required in ACI PG&E-25U-06. Accompanying narrative responses are provided below.

- Please note, enablement data included in the EPSS Reliability Study Analysis for GM-07 and ACI PG&E-25U-06 are for the circuit on which a CPZ is associated. EPSS enablement criteria are based on Meteorology outputs for circuits in HFRAs and EPSS Buffer Areas.

- Any associated conclusions or changes to threshold enablement as a result of analysis on the above:

  - In addition to reviewing the results of the GM-07 and ACI PG&E-25U-06 combined analysis, PG&E continually monitors and evaluates reliability impacts for customers when EPSS settings are enabled, and overall outage impacts for customers in EPSS scope throughout the year. While PG&E typically maintains the current EPSS enablement criteria, we may review field conditions that may result in making adjustments between Peak and Non-Peak postures.

- Any continued or additional measures PG&E is taking to minimize customer impact based on EPSS enablement:

  - In 2025, PG&E will continue to execute targeted proactive and reactive operational mitigation programs to support minimizing reliability impacts for customers in EPSS scope. PG&E will also execute proactive and reactive VM as part of its activities based on weather conditions to reduce the impacts of vegetation caused outages. Areas with prior vegetation and unknown caused outage activity will be targeted for proactive tree trimming while areas experiencing vegetation caused outages throughout the year when EPSS is enabled will be reviewed for reactive VM work.

  - PG&E will continue to execute proactive and reactive animal mitigation work including avian protection improvements and critter abatement. PG&E anticipates retrofitting select locations with historical animal caused outage activity as well as performing incident-based mitigation work following animal and unknown caused outages during EPSS enablement. Improvements included in proactive mitigation, such as phase separation at poles, may additionally benefit improved longevity of other mitigation materials leveraged, reduced outages due to phase-to-phase contact, and maintenance of midspan phase separation, all of which are anticipated to support improved reliability.

  - In 2024, PG&E expanded the scope and installation of Gridscope units across select circuits in the HFRA to over 10,000 units. PG&E anticipates expanding installation to additional areas in 2025 to further augment situational awareness

[255] The supporting document is available at: PG&E's Community Wildfire Safety Program.

of ignition potential conditions on or interacting with PG&E's assets. Gridscope may also be leveraged to supplement outage fault location and outage cause data, enabling PG&E crews to restore outages more quickly and effectively, whereby further reducing outage duration. PG&E is exploring opportunities to increase integration of Gridscope data in existing processes and procedures and leverage outage and situational details for improved real-time monitoring of system conditions. See Section 12.1 for more information about our targets, ES-03 and ES-05.

- In 2024, PG&E implemented improvements to near real-time outage tracking to provide enhanced fault location information for individual outages by leveraging remote engineering capabilities and probable fault location analysis. PG&E was able to reduce outage durations further by leveraging these improvements, enabling faster restoration for impacted customers, and will plan to continue leveraging these improvements in 2025.

- As in prior years, PG&E has identified operational and reliability improvement opportunities on critical equipment including asset repair and replacement. The EPSS Program will continue to address Critical Operating Equipment leveraging a wildfire risk and customer reliability informed approach inclusive of HFRA and additional customer exposure.

PG&E will review overall outage impacts and the outage journey experience for customers impacted by EPSS outages and additional outages throughout the year during non-peak season. PG&E is also prioritizing customers experiencing five or more EPSS outages year-over-year since the implementation of the EPSS Program for additional operational mitigation opportunities and support availability.

ACI PG&E-25U-07 – Vegetation Management Recordkeeping

Description:

Based on PG&E's response to PG&E-23B-15 in its 2025 WMP Update, Energy Safety is concerned that PG&E's current VM recordkeeping practices and planned enhancements "to capture factors for prescribing trees for removal" and to "enhance recordkeeping practices for the Focused Tree Inspection program" do not demonstrate the progress and maturity expected from the approved 2023-2025 Base WMP.

Required Progress:

In its 2026-2028 Base WMP, PG&E must demonstrate that it has:

- *Revised and improved its VM recordkeeping process in One VM to consistently and accurately "capture factors for prescribing trees for removal."*
- *Revised and improved its VM recordkeeping process for trees inspected under Focused Tree Inspection (FTI) to align with lessons learned, achieve data consistency and quality, and to collect information relevant to a tree risk assessment performed to reduce the risk of utility-related ignitions attributable to contact from vegetation. This may include adapting the ISA's Basic Tree Risk Assessment form to refine PG&E's current digitized Tree Risk Assessment.*
- *Considered adding the capability to One VM to document potential defects or issues with "inventory only trees" and other trees not prescribed work by explaining and providing the decision-making process for its consideration.*

Section and Page Number of Any Improvements:

Section 9.2, page 363.

PG&E Response:

PG&E is committed to improving its VM recordkeeping practices, which includes both technology and process enhancements.

Capturing Factors for Prescribing Trees for Removal

On January 30, 2024, PG&E completed enhancements to the One VM tool that include the capability to capture factors for prescribing trees for removal. In June 2024, an enhancement added a drop-down selection to enforce standardized, tree-specific reasons for tree removal that align with Appendix B of TD-7102P-01. Improvements and controls have been implemented requiring consistent de-listing reasons and comments throughout the One VM platform. These changes improve data quality and provide for standard methods of work. These changes enable back-office users to better understand and document operation activities.

Improving the VM Recordkeeping Process

PG&E continues to improve its VM recordkeeping process. In March 2024, PG&E implemented a digital version of the International Society of Arboriculture's Basic Tree Risk Assessment form in One VM, which was used for FTI vegetation points requiring maintenance. In July 2024, an internal review clarified procedures for FTI to create TRAQ records for three specific prescription types; Fell Tree, Targeted Prune, and Major Dismantle.

Documenting Potential Defects for 'Inventory Only' Trees

After thorough consideration regarding adding the capability to explain and document the decision-making process on trees not prescribed work, PG&E will not implement this approach at this time due to the increased time to document the inspection. Instead, the focus will be on documenting observations on trees that need work and fall into one of these three prescription types: Fell Tree, Targeted Prune, and Major Dismantle.

ACI PG&E-25U-08 – Reinspection of Trees in the Tree Removal Inventory

Description:

In response to PG&E-23B-20, PG&E described a pilot it is executing in 2024 to re-evaluate trees listed for work and included in the scope of Tree Removal Inventory (TRI).

Required Progress:

In its 2026-2028 Base WMP, PG&E must describe the results of the pilot, including any resulting actions and implementation timelines for those actions. If PG&E chooses not to expand the pilot, it must justify this choice.

Section and Page Number of Any Improvements:

Section 9.2.1, page 365.

PG&E Response:

In late 2024, PG&E began planning a pilot to re-evaluate trees listed for work within Shasta County.

The pilot involves review of individual vegetation points that had been previously marked for removal under the EVM Program with a Tree Assessment Tool (TAT) Abate score of Yes. PG&E will be inspecting approximately 8,500 TAT Abate units to determine if they still need work, have already been removed by another program, or are recommended for delisting.

The inspection will involve two parts; a level 2 inspection by a TRAQ certified arborist who will determine initial status, and then any units recommended for delisting from removal status will have a secondary evaluation by a Board-Certified Master Arborist. After the data has been evaluated by the Board-Certified Master Arborist, VM will review and determine next steps. Resulting actions or changes to procedure documents or guidance processes will be identified once the pilot has fully concluded and an analysis of the results has been completed.

ACI PG&E-23B-15 – Implementation of Focused Tree Inspections and Addressing the Risk from Hazard Trees

Description:

PG&E has committed to further implementing Focused Trees Inspections and to addressing the risk from hazard trees, but details regarding recordkeeping, refinement of the Areas of Concerns, and long-term- planning remain unclear.

Required Progress:[256]

In its 2026-2028 Base WMP, PG&E must present its plan for consistent HFTD-wide hazard tree-related risk reduction by inspection and remediation. In its development of this plan, PG&E must continue its dialogue with its peer electrical corporations and Energy Safety and remain abreast of hazard tree inspection and remediation strategies including, but not limited to, tools for risk assessment, recordkeeping practices, and frameworks for risk- informed inspections (i.e., when, where, and how often to inspect for hazard trees based on risk).

Section and Page Number of Any Improvements:

Section 9.2.2, page 370.

PG&E Response:

PG&E is committed to improving its inspection and remediation process for hazard trees. Specifically, PG&E is updating its inspections in 2026-2028 to vary the layers of inspection based on the level of vegetation risk (including hazard trees) and WFC in the HFTD territory. PG&E's Distribution Routine Inspection program will patrol the entire OH distribution system annually. PG&E's Distribution Hazard Patrol Program will entail additional proactive inspections conducted on a subset of HFTD miles, identified by areas of higher vegetation risk and WFC. In the areas of highest vegetation risk and WFC, PG&E will leverage remote sensing technologies to monitor and identify additional vegetation work necessary. For additional information, see Section 9.2.2, Distribution Hazard Patrol.

PG&E will also continue to benchmark with peer electrical corporations and engage in dialogue with Energy Safety in order to remain abreast of hazard tree inspections and remediation strategies. The leveraging of technology to improve risk assessment, inspection strategy, and recordkeeping practices continues to be a topic of interest across peers. Remote sensing technologies like satellite or Light Detection and Ranging (LiDAR) not only provide alternative methods of identifying possible encroachments, but also could identify potential hazard trees that could strike PG&E lines. This information could provide inspectors with better hazard tree identification, identify trees that require a more thorough inspection, and improve recordkeeping.

256 In Energy Safety's Decision on PG&E 2023-2025 WMP, PG&E-23-15 included requirements for progress reporting in PG&E's 2025 WMP Update; this language has been removed from this decision as it does not apply towards the required progress for the 2026-2028 Base WMP.

PG&E will continue benchmarking with other peer electrical corporations and Energy Safety as these technologies evolve.

ACI PG&E-23B-16 – Updating the Wood Management Procedure

Description:

PG&E's Wood Management procedure only addresses large wood generated by post-fire activities and Enhanced Vegetation Management (EVM), does not consider wildfire and safety risks associated with leaving wood on site, and may not sufficiently take into consideration potential benefits to the program from improved customer relations.

Required Progress:

In its 2026-2028 Base WMP, PG&E must:

- *Benchmark the scope of its Wood Management program with, at minimum, SCE and Liberty Utilities, and justify the differences in scope.*
- *Provide a response detailing whether PG&E has considered how offering wood removal and disposal services to customers may reduce refusals related to VM and how that consideration has informed any updates to PG&E's Wood Management program for the 2026-2028 WMP Base WMP.*
- *Attach an updated version of its Wood Management Procedure (TD-7102P-26) that:*
    - *Reflects its current portfolio of VM programs (e.g., FTI, TRI, VM for Operational Mitigations (VMOM));*
    - *Considers the wildfire risk related to accumulated fuels generated by PG&E's VM activities;*
    - *Considers the risk and safety impact of leaving large woody debris onsite including, but not limited to:*
        - *Blocking, hindering, or potentially blocking (e.g., roll or blow into) ingress or egress (roads, driveways, walkways, etc.);*
        - *Violating defensible space laws or ordinances such as PRC Section 4291 and Government Code Section 51182;*
        - *Impede watercourses and drainages; and*
        - *Otherwise create a hazard.*

Section and Page Number of Any Improvements:

Section 9.5, page 386.

PG&E Response:

PG&E's Updated Wood Management Procedure

In November 2024, PG&E updated its wood management procedure, which reflects implementation of a consistent approach for responding to customer requests for wood management. Updates to VM wood management practices have been accomplished through the Utility Standard, TD-7116S and Utility Procedure, TD-7116P-01, which replaced Utility Procedure TD-7102P-26.[257] Updates include:

- Applicability to the current portfolio of VM distribution programs;
- Alignment to industry practices related to accumulated fuels generated by VM activities; and
- Consideration for risk and safety impact of leaving wood management debris in alignment with regulatory and industry leading practices, including PRC 4291.

To deliver a more consistent customer experience, PG&E wood management activities now apply on a case-by-case basis in response to customer requests on distribution VM programs.

To the extent that new best practices are identified and applicable, PG&E will consider further updates to the utility standard and procedure.

Consideration of Wood Management in Customer Refusal Resolution

PG&E has considered how offering wood removal and disposal services to customers may reduce refusals related to VM and now offers wood management where feasible according to our standards on a case-by-case basis in response to customer requests on all distribution VM programs.

Benchmarking Wood Management Practices

PG&E is committed to improving its wood management practices and is working diligently toward this goal. We began holding benchmarking discussions regarding wood management practices with SCE and SDG&E in 2023 and identified high-level similarities and differences between each utility's programs. Our initial benchmarking discussions with SCE and SDG&E and our review of Liberty's procedure highlighted each utility's varying policies due to differences in terrain, as well as customer and stakeholder bases. The result of the benchmarking helped shape our new Wood Management Standard and Procedure. Absent a consistent approach across utilities, we aligned and updated our Standard and Procedure to reflect the common ground of PRC 4291. See Utility Standard TD-7116S.

As directed, we will continue to benchmark with other California utilities, including SCE, SDG&E, and Liberty Utilities, and intend to share any revisions to our procedure as part of this work. This benchmarking will support continued identification of best practices

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[257] The supporting document is available at: PG&E's Community Wildfire Safety Program.

with the goal of building consistent industry-wide application. We expect topics for benchmarking will include:

- How offering wood removal and disposal services to customers may reduce refusals related to vegetation management and how that consideration has informed any updates to wood management programs.

- Whether each utility's respective policies:

  - Reflect its current portfolio of vegetation management programs.

  - Consider the wildfire risk related to accumulated fuels generated by its vegetation management activities.

  - Consider the risk and safety impact of leaving large woody debris onsite including, but not limited to blocking, hindering, or potentially blocking (e.g., roll or blow into) ingress or egress (roads, driveways, walkways, etc.).

ACI PG&E-23B-17 – Consolidation of Vegetation Inspection Programs

Description:

PG&E's VM program for distribution circuits is complex, resulting in multiple touchpoints for customers and overlapping scopes of work for PG&E's personnel.

Required Progress:

In its 2026-2028 Base WMP, PG&E must present a plan to consolidate its vegetation inspection programs for distribution circuits in the HFTD with the following objectives:

- *Reduce the number of annual touchpoints from inspectors and tree crews due to overlapping scopes of work.*
- *Streamline the distribution inspection procedure, including reduction and/or consolidation of its attachments, to reduce confusion among government agencies, PG&E's customers, and vegetation personnel.*
- *Address the risk from vegetation contact through vegetation inspection, trimming, and removal while complying with applicable laws and regulations.*

Section and Page Number of Any Improvements:

Section 9.2, page 363.

PG&E Response:

In the 2023-2025 WMP, PG&E introduced three transitional programs that followed the EVM Program:

- FTI;
- TRI; and
- VMOM.

PG&E is in the process of evaluating which component(s) of the FTI and TRI scope will be incorporated into the Distribution Routine Patrol Program. This analysis will be based on findings from efficacy studies planned to be performed in 2025. PG&E will incorporate VMOM into activities described in Section 9.9.1.

For the 2026-2028 time period, PG&E will streamline our VM inspection programs, while targeting high risk areas of the system to continuously reduce ignitions associated with vegetation caused outages. PG&E will focus on consolidating VM inspection programs by leveraging technology to inform and/or supplement planning, execution, or verification of worked performed, as well as utilizing and evolving operational analytics to enable risk-informed work execution. PG&E will continue to address the risk from vegetation contact through vegetation inspection by following its Distribution Inspection Procedure, which provides a consistent process for complying with applicable laws and regulations. See Revision Notice Response to Critical Issue RN-PGE-26-09 for additional information.

In 2025, PG&E will explore the use of technologies to support distribution inspections. PG&E will use data gathered from proven remote sensing technologies to analyze how distribution inspections could be further evolved to incorporate remote sensing techniques. Remote sensing techniques that will be considered could include satellite, LiDAR, ortho imagery, or other available technology that can provide accurate and efficient insights into vegetation risk. PG&E may consider utilizing remote sensing in lieu of ground-based inspections.

ACI PG&E-23B-18 – Improving Vegetation Management Inspector Qualifications

Description:

It is essential that PG&E ensure it has qualified personnel for vegetation inspections and has trained these personnel to adequately perform vegetation inspections.

Required Progress:

In its 2026-2028 Base WMP, PG&E must:

- *Present a plan to improve the level of qualifications and training of its current VM Inspectors (both contract and employee).*
- *Explain and provide the decision-making process for its consideration of updates to the minimum qualification and training requirements for its VM Inspectors.*

Section and Page Number of Any Improvements:

Section 9.13.2, page 430.

PG&E Response:

Improving the Qualifications and Training of VM Inspectors

PG&E has implemented multiple initiatives to continue to improve the level of qualifications and training of its current VM Inspectors. These initiatives include:

- *Training Requirements Standardization*: PG&E has implemented a process of profiling training courses within the VM organization based on personnel role and internal employee or contractor status. Once training courses are profiled, users will have a defined time to take and complete the courses.
- *Refresher Courses*: VM hosts an annual refresher course training for internal employee and contractor inspectors to communicate significant programmatic and procedural changes.
- *On-the-Job Training*: On-the-job training consists of onboarding sessions, in-field training, periodic program and operations updates.

The Process for Updating Minimum Qualifications and Training Requirements

Updates to the training requirements for PG&E VM Inspectors are triggered by changes to standards and procedures. We may also receive and incorporate improvement opportunities identified in the field by Quality Management. Finally, Quality Learning forums are conducted by Quality Management leaders in collaboration with local VM Operations to review findings and trends. During these forums, opportunities for improvement are discussed and corrective actions are established, which may include training updates, procedural modifications, and/or contractor leadership meetings.

ACI PG&E-23B-21 – Identification of High-Risk Species for Focused Tree Inspections

Description:

In the procedure for PG&E's Focused Tree Inspection, the methodology for identifying species for which inspectors are to "apply increase scrutiny" relies exclusively on outage rates.

Required Progress:

In its 2026-2028 Base WMP, PG&E must define criteria for determining which species warrant increased scrutiny during Focused Tree Inspections and other inspections. PG&E must detail its methodologies for determining these species.

Section and Page Number of Any Improvements:

Section 9.2.1, page 365.

PG&E Response:

PG&E incorporates consideration of tree species as part of its standardized work as defined in the Distribution Inspection Procedure. Historic tree species outage data source is available to the inspectors. The Distribution Inspection Procedure states that VM inspectors should review multiple data sources including outage data in preparation for inspection.

PG&E has developed a tool to improve situational awareness during pre-patrol planning, which includes outage and ignition dashboards. The dashboard allows the user to drill down to the circuit or CPZ level to see historical outage and ignition causes by species, diameter, and failure. Given the diversity of PG&E's service territory, localized situational awareness allows each area to provide inspectors with the most current data to inform inspections.

ACI PG&E-23B-22 – Continuation of Effectiveness of Enhanced Clearances Joint Study

Description:

The large IOUs have jointly made progress addressing the Progression of Effectiveness of Enhanced Clearances Joint Study 2022 ACI (SDGE-22-20, PG&E-22-28, and SCE-22-18). Energy Safety expects the large IOUs and their contracted third party to continue their efforts and meet the requirements of this ongoing ACI.[258]

Required Progress:[259]

With its 2026-2028 Base WMP, PG&E, along with SCE and SDG&E, must attach a white paper that discusses:

- *The large IOUs' joint evaluation of the effectiveness of enhanced clearances including, but not limited to, the effectiveness of enhanced clearances in reducing tree-caused outages and ignitions.*
- *The large IOUs' joint recommendations for updates and changes to utility VM operations and best management practices for wildfire safety based on this study. This may include the IOUs' recommendations for updates to regulations related to clearance distances.*

Section and Page Number of Any Improvements:

Section 9.2, page 363.

PG&E Response:

In response to this ACI, three investor-owned utilities ("IOUs"; PG&E, SDG&E, and SCE) conducted a joint study to quantify the benefits of proactive pruning to 12 feet or more clearance at time of trim. See the IOU Effectiveness of Enhanced Clearances White Paper available at PG&E's Community Wildfire Safety Program. The recommendations from the third-party analysis and the white paper are detailed in Table 9 located at the end of the document (pp. 38-39).

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258 *The objectives for the Enhanced Clearances Joint Study were defined in PG&E-21-23, Final Action Statement on the 2021 WMP Update of PG&E, p. Appendix-16 (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=51745&shareable=true, accessed June 4, 2024).*

259 *In Energy Safety's Decision on PG&E 2023-2025 WMP, PG&E-23-22 included requirements for progress reporting in PG&E's 2025 WMP Update; this language has been removed from this decision as it does not apply towards the required progress for the 2026-2028 Base WMP.*

PG&E's data sample, used in this study, does not holistically represent the effectiveness of combined mitigations. PG&E incorporates lifecycle cost of overhead mitigations into its mitigation selection process. One of the main alternative mitigations to undergrounding is the use of covered conductor, which may be selected for circuit segments with fewer trees. Since covered conductor has been a recent engineering mitigation measure deployed by IOUs, additional time will be required to collect data samples and further analyze the effectiveness of combined mitigations.